May 23, 1996

Mr. William L. Stewart
Executive Vice President, Nuclear
Arizona Public Service Company
Post Office Box 53999
Phoenix, Arizona 85072-3999

SUBJECT: ISSUANCE OF AMENDMENTS FOR THE PALO VERDE NUCLEAR GENERATING STATION UNIT NO. 1 (TAC NO. M94541), UNIT NO. 2 (TAC NO. M94542), AND UNIT NO. 3 (TAC NO. M94543)

Dear Mr. Stewart:

The Commission has issued the enclosed Amendment No. 108 to Facility Operating License No. NPF-41, Amendment No. 100 to Facility Operating License No. NPF-51, and Amendment No. 80 to Facility Operating License No. NPF-74 for the Palo Verde Nuclear Generating Station, Unit Nos. 1, 2, and 3, respectively. The amendments consist of changes to the operating licenses and Technical Specifications in response to your application dated January 5, 1996, as supplemented by letters dated April 19, 1996, May 1, 1996, and May 10, 1996.

This amendment would revise the operating licenses and TS Section 1.26 to increase the authorized rated thermal power. The amendment also would revise TS 4.1.1.4, 3.1.3.4, and 3.2.6 (Figure 3.2-1) to lower the allowable reactor coolant system cold leg temperature limits for each of the three PVNGS Units, and revise TS 3.4.2.1 and 3.4.2.2 to lower the pressurizer safety valve setpoints by 25 psia for Units 1 and 3. The Unit 2 pressurizer safety valve setpoints in TS 3.4.2.1 and 3.4.2.2 were revised by Amendment 78, approved March 28, 1995, to the same values being requested for Units 1 and 3.

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly Federal Register notice.

Sincerely,

Original signed by:

Charles R. Thomas, Project Manager
Project Directorate IV-2
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-528, STN 50-529
and STN 50-530

Enclosures:
1. Amendment No. 108 to NPF-41
2. Amendment No. 100 to NPF-51
3. Amendment No. 80 to NPF-74
4. Safety Evaluation

cc w/encls: See next page

CP-1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 23, 1996

Mr. William L. Stewart
Executive Vice President, Nuclear
Arizona Public Service Company
Post Office Box 53999
Phoenix, Arizona 85072-3999

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This amendment would revise the operating licenses and TS Section 1.26 to increase the authorized rated thermal power. The amendment also would revise TS 4.1.1.4, 3.1.3.4, and 3.2.6 (Figure 3.2-1) to lower the allowable reactor coolant system cold leg temperature limits for each of the three PVNGS Units, and revise TS 3.4.2.1 and 3.4.2.2 to lower the pressurizer safety valve setpoints by 25 psia for Units 1 and 3. The Unit 2 pressurizer safety valve setpoints in TS 3.4.2.1 and 3.4.2.2 were revised by Amendment 78, approved March 28, 1995, to the same values being requested for Units 1 and 3.

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Sincerely,

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Project Directorate IV-2
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-528, STN 50-529
and STN 50-530

Enclosures:
1. Amendment No. 108 to NPF-41
2. Amendment No. 100 to NPF-51
3. Amendment No. 80 to NPF-74
4. Safety Evaluation

cc w/encls: See next page

cc w/encls:
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DOCUMENT NAME: PV94541 *See previous concurrence

OFC	PDIV-2/LA	PDIV-2/PM	NRR:HHFB	TECH ED	BC:SICB	BC:SPLB
NAME	EPeyton	CThomas	CThomas*	PKleene*	JWermiel*	TMarsh*
DATE	5/16/96	5/16/96	3/14/96	5/1/96	3/14/96	5/9/96

OFC	C:SRXB	PERB	NRR:EMEB	SCSB	PDIV-2/PD	OGC
NAME	RJones*	REmch*	RWessman*	CBerlinger*	WBateman	
DATE	4/15/96	5/9/96	4/17/96	3/14/96	5/21/96	5/20/96

OFC	EMCB	DRPW:D	ADT	ADP	NRR:D
NAME	JStrosnider*	JRoe	AThadani	RZimmerman	WRussell
DATE	4/11/96	5/ /96	5/20/96	5/ /96	5/22/96

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ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-528

PALO VERDE NUCLEAR GENERATING STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 108
License No. NPF-41

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated January 5, 1996, as supplemented by letters dated April 19, 1996, May 1, 1996, May 10, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C(1) and 2.C(2) of Facility Operating License No. NPF-41 are hereby amended to read as follows:

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 108, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective as of successful completion of the Cycle 7 reload analysis and to be implemented prior to startup from Unit 1 refueling outage six.

FOR THE NUCLEAR REGULATORY COMMISSION

W. T. Russell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachments: 1. Page 4 of License
2. Changes to the Technical Specifications

Date of Issuance: May 23, 1996

Page 4 is attached, for convenience, for the composite license to reflect this change. Please remove page 4 of the existing license and replace with the attached page.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 108, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Operating Staff Experience Requirements

APS shall have operators on each shift who meet the requirements described in Attachment 2. Attachment 2 is hereby incorporated into this license.

(5) Post-Fuel-Loading Initial Test Program (Section 14, SER and SSER 2)*

Any changes in the Initial Test Program described in Section 14 of the FSARs (Palo Verde and CESSAR) made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

ATTACHMENT TO LICENSE AMENDMENT

AMENDMENT NO. 108 TO FACILITY OPERATING LICENSE NO. NPF-41

DOCKET NO. STN 50-528

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised pages are identified by Amendment number and contain marginal lines indicating the areas of change. The corresponding overleaf pages are also provided to maintain document completeness.

REMOVE	INSERT
1-5	1-5
3/4 1-5	3/4 1-5
3/4 1-19	3/4 1-19
3/4 2-8	3/4 2-8
3/4 4-7	3/4 4-7
3/4 4-8	3/4 4-8
B 3/4 1-5	B 3/4 1-5
B 3/4 4-12	B 3/4 4-12

PHYSICS TESTS

1.21 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANAR RADIAL PEAKING FACTOR - F_{xy}

1.22 The PLANAR RADIAL PEAKING FACTOR is the ratio of the peak to plane average power density of the individual fuel rods in a given horizontal plane, excluding the effects of azimuthal tilt.

PRESSURE BOUNDARY LEAKAGE

1.23 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.24 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processsing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.25 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.26 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3876 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.27 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.4 The Reactor Coolant System lowest operating loop temperature (T_{cold}) shall be greater than or equal to 545°F.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{cold}) less than 545°F, restore T_{cold} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.4 The Reactor Coolant System temperature (T_{cold}) shall be determined to be greater than or equal to 545°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{cold} is less than 550°F.

#With K_{eff} greater than or equal to 1.0.

3/4.1.2 BORATION SYSTEMS

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE:

a. If only the spent fuel pool in Specification 3.1.2.5a. is OPERABLE, a flow path from the spent fuel pool via a gravity feed connection and a charging pump to the Reactor Coolant System.

b. If only the refueling water tank in Specification 3.1.2.5b. is OPERABLE, a flow path from the refueling water tank via either a charging pump, a high pressure safety injection pump, or a low pressure safety injection pump to the Reactor Coolant System.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and regulating) CEA drop time, from a fully withdrawn position, shall be less than or equal to 4 seconds from when the electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90% insertion position with:

a. T_{cold} greater than or equal to 550°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With the drop time of any full-length CEA determined to exceed the above limit, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time of full-length CEAs shall be demonstrated through measurement prior to reactor criticality:

a. For all CEAs following each removal and reinstallation of the reactor vessel head,

b. For specifically affected individual CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months.

SHUTDOWN CEA INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown CEAs shall be withdrawn to at least 144.75 inches.

APPLICABILITY: MODES 1 and 2*#.

ACTION:

With a maximum of one shutdown CEA withdrawn to less than 144.75 inches, except for surveillance testing pursuant to Specification 4.1.3.1.2, within 1 hour either:

a. Withdraw the CEA to at least 144.75 inches, or

b. Declare the CEA inoperable and comply with Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown CEA shall be determined to be withdrawn to at least 144.75 inches:

a. Within 15 minutes prior to withdrawal of any CEAs in regulating groups during an approach to reactor criticality, and

b. At least once per 12 hours thereafter except during time intervals when both CEAC's are inoperable, then verify the individual CEA positions at least once per 4 hours.

*See Special Test Exception 3.10.2.

#With K_{eff} greater than or equal to 1.

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.2.6 The reactor coolant cold leg temperature (T_c) shall be within the Area of Acceptable Operation shown in Figure 3.2-1.

APPLICABILITY: MODE 1* and 2*#.

ACTION:

With the reactor coolant cold leg temperature exceeding its limit, restore the temperature to within its limit within 2 hours or be in HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The reactor coolant cold leg temperature shall be determined to be within its limit at least once per 12 hours.

---

*See Special Test Exception 3.10.4.
#With K_{eff} greater than or equal to 1

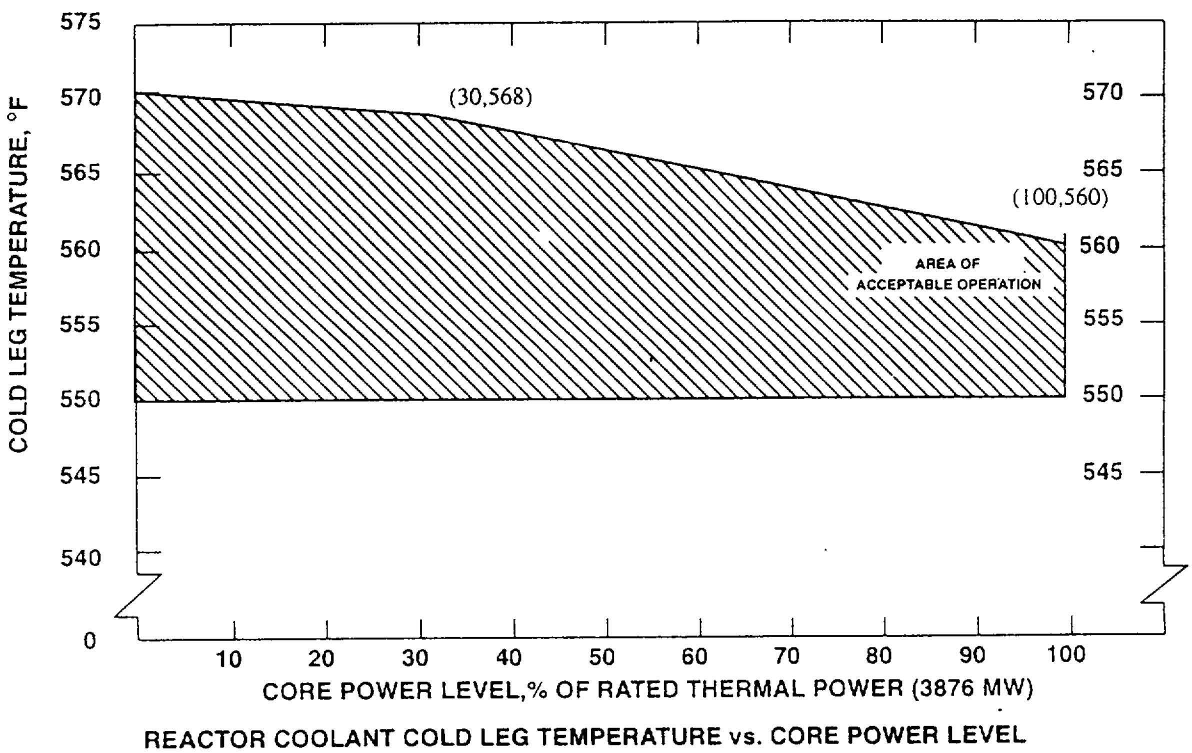

FIGURE 3.2-1

REACTOR COOLANT COLD LEG TEMPERATURE VS. CORE POWER LEVEL

REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer code safety valve shall be OPERABLE with a lift setting of 2475 psia +3, -1%*.

APPLICABILITY: MODE 4

ACTION:

a. With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE shutdown cooling loop into operation.

b. The provisions of Specification 3.0.4 may be suspended for up to 12 hours for entering into and during operation in MODE 4 for purposes of setting the pressurizer code safety valves under ambient (HOT) conditions provided a preliminary cold setting was made prior to heatup.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

REACTOR COOLANT SYSTEM

OPERATING

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer code safety valves shall be OPERABLE with a lift setting of 2475 psia +3, -1%*.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours with the shutdown cooling system suction line relief valves aligned to provide overpressure protection for the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

MOVABLE CONTROL ASSEMBLIES (Continued)

and LSSS setpoints determination. Therefore, time limits have been imposed on operation with inoperable CEAs to preclude such adverse conditions from developing.

Operability of at least two CEA position indicator channels is required to determine CEA positions and thereby ensure compliance with the CEA alignment and insertion limits. The CEA "Full In" and "Full Out" limits provide an additional independent means for determining the CEA positions when the CEAs are at either their fully inserted or fully withdrawn positions. Therefore, the ACTION statements applicable to inoperable CEA position indicators permit continued operations when the positions of CEAs with inoperable position indicators can be verified by the "Full In" or "Full Out" limits.

CEA positions and OPERABILITY of the CEA position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

The maximum CEA drop time restriction is consistent with the assumed CEA drop time used in the safety analyses. Measurement with T_{cold} greater than or equal to 550°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

Several design steps were employed to accommodate the possible CEA guide tube wear which could arise from CEA vibrations when fully withdrawn. Specifically, a programmed insertion schedule will be used to cycle the CEAs between the full out position ("FULL OUT" LIMIT) and 3.0 inches inserted over the fuel cycle. This cycling will distribute the possible guide tube wear over a larger area, thus minimizing any effects. To accommodate this programmed insertion schedule, the fully withdrawn position was redefined, in some cases, to be 144.75 inches or greater.

The establishment of LSSS and LCOs requires that the expected long- and short-term behavior of the radial peaking factors be determined. The long-term behavior relates to the variation of the steady-state radial peaking factors with core burnup and is affected by the amount of CEA insertion assumed, the portion of a burnup cycle over which such insertion is assumed and the expected power level variation throughout the cycle. The short-term behavior relates to transient perturbations to the steady-state radial peaks due to radial xenon redistribution. The magnitudes of such perturbations depend upon the expected use of the CEAs during anticipated power reductions

MOVABLE CONTROL ASSEMBLIES (Continued)

and load maneuvering. Analyses are performed based on the expected mode of operation of the NSSS (base load maneuvering, etc.) and from these analyses CEA insertions are determined and a consistent set of radial peaking factors defined. The Long Term Steady State and Short Term Insertion Limits are determined based upon the assumed mode of operation used in the analyses and provide a means of preserving the assumptions on CEA insertions used. The limits specified serve to limit the behavior of the radial peaking factors within the bounds determined from analysis. The actions specified serve to limit the extent of radial xenon redistribution effects to those accommodated in the analyses. The Long and Short Term Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 are specified for the plant which has been designed for primarily base loaded operation but which has the ability to accommodate a limited amount of load maneuvering.

The Transient Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 and the Shutdown CEA Insertion Limits of Specification 3.1.3.5 ensure that (1) the minimum SHUTDOWN MARGIN is maintained, and (2) the potential effects of a CEA ejection accident are limited to acceptable levels. Long-term operation at the Transient Insertion Limits is not permitted since such operation could have effects on the core power distribution which could invalidate assumptions used to determine the behavior of the radial peaking factors.

The PVNGS CPC and COLSS systems are responsible for the safety and monitoring functions, respectively, of the reactor core. COLSS monitors the DNB Power Operating Limit (POL) and various operating parameters to help the operator maintain plant operation within the limiting conditions for operation (LCO). Operating within the LCO guarantees that in the event of an Anticipated Operational Occurrence (AOO), the CPCs will provide a reactor trip in time to prevent unacceptable fuel damage.

The COLSS reserves the Required Overpower Margin (ROPM) to account for the Loss of Flow (LOF) and CEA misoperation transients. When the COLSS is Out of Service (COOS), the monitoring function is performed via the CPC calculation of DNBR in conjunction with Technical Specification COOS Limit Lines specified in the CORE OPERATING LIMITS REPORT which restrict the reactor power sufficiently to preserve the ROPM.

The reduction of the CEA deviation penalties in accordance with the CEAC (Control Element Assembly Calculator) sensitivity reduction program has been performed. This task involved setting many of the inward single CEA deviation penalty factors to 1.0. An inward CEA deviation event in effect would not be accompanied by the application of the CEA deviation penalty in either the CPC DNB and LHR (Linear Heat Rate) calculations for those CEAs with the reduced penalty factors. The protection for an inward CEA deviation event is thus accounted for separately.

PRESSURE/TEMPERATURE LIMITS (Continued)

5 EFPY, etc. and are based upon the irradiation damage prediction by the end of the period. Accordingly, each time P-T limits change, the LTOP system needs to be re-analyzed and modified, if necessary, to continue its function.

A typical LTOP system includes pressure relieving devices and a number of administrative and operational controls. Each of the Palo Verde Units has a similar LTOP system that includes two Shutdown Cooling System suction line relief valves for transient mitigation. Each relief valve has an opening setpoint of 467 psig which, in combination with certain other limiting conditions for operation contained in Technical Specifications, comprises the LTOP system.

Previously, the LTOP enable temperatures during heatup and cooldown have been determined at the intersections between a horizontal line corresponding to the safety valve setpoint (2475 psia) and the most limiting P-T limit curves for heatup and cooldown, respectively. Note that the enable temperature generally identifies the upper temperature limit below which the LTOP system has to be operable.

In this analysis, the LTOP enable temperatures were determined in accordance with a definition contained in the latest revision of the Standard Review Plan 5.2.2. According to SRP 5.2.2 the LTOP enable temperature is "the water temperature corresponding to a metal temperature of at least RT_{NDT} + 90°F at the beltline location (1/4T or 3/4T) that is controlling in the Appendix G limit calculations." The heatup and cooldown rate limitations assure the limits of Appendix G to 10 CFR 50 will not be exceeded with overpressure protection provided by the primary safety valves. The various categories of load cycles used for design purposes are provided in Chapters 3 and 5 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so as not to exceed the limit lines of Figures 3.4-2a and 3.4-2b. This ensures that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

3/4.4.9 STRUCTURAL INTEGRITY

The inservice inspection and testing programs for ASME Code Class 1, 2, and 3 components ensure that the structural integrity and operational readiness of these components will be maintained at an acceptable level throughout the life of the plant. These programs are in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50.55a(g) except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i).

Components of the Reactor Coolant System were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1974 Edition and Addenda through Summer 1975.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-529

PALO VERDE NUCLEAR GENERATING STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 100
License No. NPF-51

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated January 5, 1996, as supplemented by letters dated April 19, 1996, May 1, 1996, and May 10, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C(1) and 2.C(2) of Facility Operating License No. NPF-51 are hereby amended to read as follows:

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 100, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective as of its date of issuance to be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

WTRussell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachments: 1. Page 4 of License
2. Changes to the Technical Specifications

Date of Issuance: May 23, 1996

Page 4 is attached, for convenience, for the composite license to reflect this change. Please remove page 4 of the existing license and replace with the attached page.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 100, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Operating Staff Experience Requirements (Section 13.1.2, SSER 9)*

APS shall have a licensed senior operator on each shift who has had at least six months of hot operating experience on the same type of plant, including startup and shutdown experience and at least six weeks at power levels greater than 20% of full power.

(5) Initial Test Program (Section 14, SER and SSER 2)

Any changes in the initial test program described in Section 14 of the FSARs (Palo Verde and CESSAR), made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

ATTACHMENT TO LICENSE AMENDMENT

AMENDMENT NO. 100 TO FACILITY OPERATING LICENSE NO. NPF-51

DOCKET NO. STN 50-529

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change. The corresponding overleaf pages are also provided to maintain document completeness.

REMOVE	INSERT
1-5	1-5
3/4 1-5	3/4 1-5
3/4 1-19	3/4 1-19
3/4 2-8	3/4 2-8
B 3/4 1-5	B 3/4 1-5

PHYSICS TESTS

1.21 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANAR RADIAL PEAKING FACTOR - F_{xy}

1.22 The PLANAR RADIAL PEAKING FACTOR is the ratio of the peak to plane average power density of the individual fuel rods in a given horizontal plane, excluding the effects of azimuthal tilt.

PRESSURE BOUNDARY LEAKAGE

1.23 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.24 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.25 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.26 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3876 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.27 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.4 The Reactor Coolant System lowest operating loop temperature (T_{cold}) shall be greater than or equal to 545°F.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{cold}) less than 545°F, restore T_{cold} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.4 The Reactor Coolant System temperature (T_{cold}) shall be determined to be greater than or equal to 545°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{cold} is less than 550°F.

#With K_{eff} greater than or equal to 1.0.

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE:

a. If only the spent fuel pool in Specification 3.1.2.5a. is OPERABLE, a flow path from the spent fuel pool via a gravity feed connection and a charging pump to the Reactor Coolant System.

b. If only the refueling water tank in Specification 3.1.2.5b. is OPERABLE, a flow path from the refueling water tank via either a charging pump, a high pressure safety injection pump, or a low pressure safety injection pump to the Reactor Coolant System.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and regulating) CEA drop time, from a fully withdrawn position, shall be less than or equal to 4 seconds from when the electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90% insertion position with:

a. T_{cold} greater than or equal to 550°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With the drop time of any full-length CEA determined to exceed the above limit, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time of full-length CEAs shall be demonstrated through measurement prior to reactor criticality:

a. For all CEAs following each removal and reinstallation of the reactor vessel head,

b. For specifically affected individual CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months.

REACTIVITY CONTROL SYSTEMS

SHUTDOWN CEA INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown CEAs shall be withdrawn to at least 144.75 inches.

APPLICABILITY: MODES 1 and 2*#.

ACTION:

With a maximum of one shutdown CEA withdrawn to less than 144.75 inches, except for surveillance testing pursuant to Specification 4.1.3.1.2, within 1 hour either:

a. Withdraw the CEA to at least 144.75 inches, or

b. Declare the CEA inoperable and comply with Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown CEA shall be determined to be withdrawn to at least 144.75 inches:

a. Within 15 minutes prior to withdrawal of any CEAs in regulating groups during an approach to reactor criticality, and

b. At least once per 12 hours thereafter except during time intervals when both CEAC's are inoperable, then verify the individual CEA positions at least once per 4 hours.

*See Special Test Exception 3.10.2.

#With K_{eff} greater than or equal to 1.

POWER DISTRIBUTION LIMITS

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.2.6 The reactor coolant cold leg temperature (T_c) shall be within the Area of Acceptable Operation shown in Figure 3.2-1.

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With the reactor coolant cold leg temperature exceeding its limit, restore the temperature to within its limit within 2 hours or be in HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The reactor coolant cold leg temperature shall be determined to be within its limit at least once per 12 hours.

*See Special Test Exception 3.10.4.
#With K_{eff} greater than or equal to 1

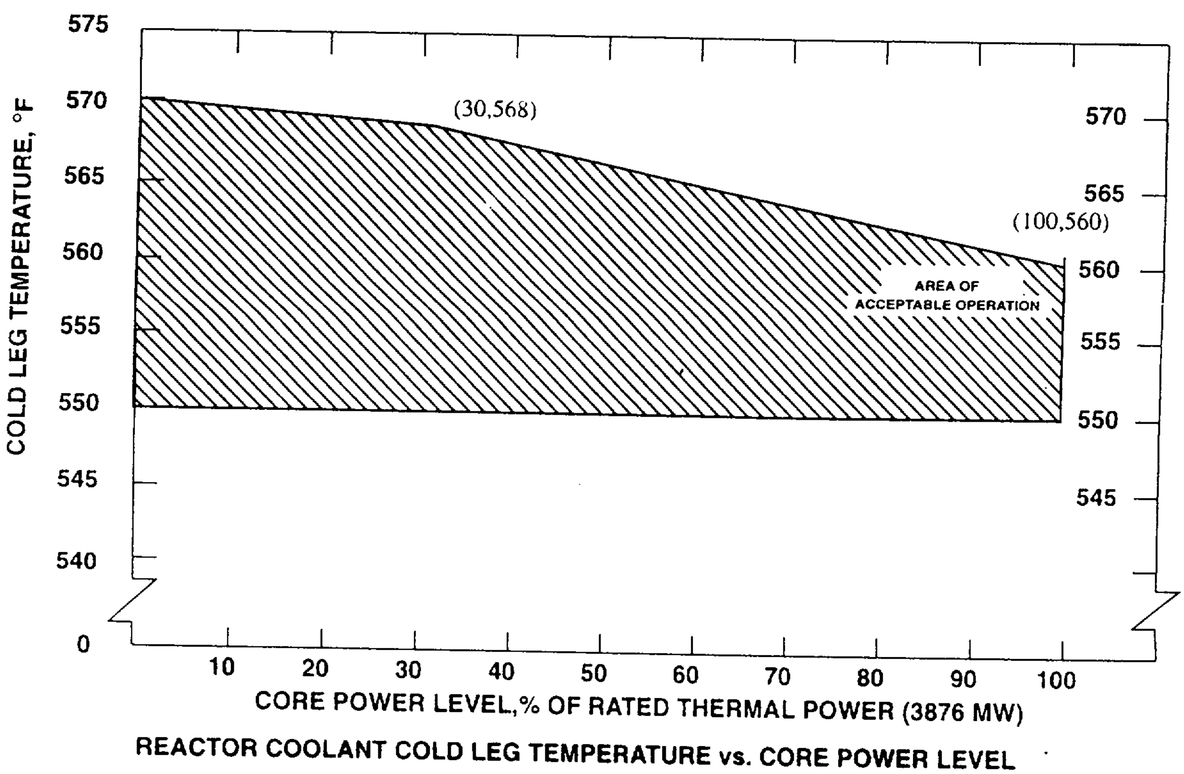

FIGURE 3.2-1

REACTOR COOLANT COLD LEG TEMPERATURE VS. CORE POWER LEVEL

MOVABLE CONTROL ASSEMBLIES (Continued)

and LSSS setpoints determination. Therefore, time limits have been imposed on operation with inoperable CEAs to preclude such adverse conditions from developing.

Operability of at least two CEA position indicator channels is required to determine CEA positions and thereby ensure compliance with the CEA alignment and insertion limits. The CEA "Full In" and "Full Out" limits provide an additional independent means for determining the CEA positions when the CEAs are at either their fully inserted or fully withdrawn positions. Therefore, the ACTION statements applicable to inoperable CEA position indicators permit continued operations when the positions of CEAs with inoperable position indicators can be verified by the "Full In" or "Full Out" limits.

CEA positions and OPERABILITY of the CEA position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

The maximum CEA drop time restriction is consistent with the assumed CEA drop time used in the safety analyses. Measurement with T_{cold} greater than or equal to 550°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

Several design steps were employed to accommodate the possible CEA guide tube wear which could arise from CEA vibrations when fully withdrawn. Specifically, a programmed insertion schedule will be used to cycle the CEAs between the full out position ("FULL OUT" LIMIT) and 3.0 inches inserted over the fuel cycle. This cycling will distribute the possible guide tube wear over a larger area, thus minimizing any effects. To accommodate this programmed insertion schedule, the fully withdrawn position was redefined, in some cases, to be 144.75 inches or greater.

The establishment of LSSS and LCOs requires that the expected long- and short-term behavior of the radial peaking factors be determined. The long-term behavior relates to the variation of the steady-state radial peaking factors with core burnup and is affected by the amount of CEA insertion assumed, the portion of a burnup cycle over which such insertion is assumed and the expected power level variation throughout the cycle. The short-term behavior relates to transient perturbations to the steady-state radial peaks due to radial xenon redistribution. The magnitudes of such perturbations depend upon the expected use of the CEAs during anticipated power reductions

MOVABLE CONTROL ASSEMBLIES (Continued)

and load maneuvering. Analyses are performed based on the expected mode of operation of the NSSS (base load maneuvering, etc.) and from these analyses CEA insertions are determined and a consistent set of radial peaking factors defined. The Long Term Steady State and Short Term Insertion Limits are determined based upon the assumed mode of operation used in the analyses and provide a means of preserving the assumptions on CEA insertions used. The limits specified serve to limit the behavior of the radial peaking factors within the bounds determined from analysis. The actions specified serve to limit the extent of radial xenon redistribution effects to those accommodated in the analyses. The Long and Short Term Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 are specified for the plant which has been designed for primarily base loaded operation but which has the ability to accommodate a limited amount of load maneuvering.

The Transient Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 the Shutdown CEA Insertion Limits of Specification 3.1.3.5 ensure that (1) the minimum SHUTDOWN MARGIN is maintained, and (2) the potential effects of a CEA ejection accident are limited to acceptable levels. Long-term operation at the Transient Insertion Limits is not permitted since such operation could have effects on the core power distribution which could invalidate assumptions used to determine the behavior of the radial peaking factors.

The PVNGS CPC and COLSS systems are responsible for the safety and monitoring functions, respectively, of the reactor core. COLSS monitors the DNB Power Operating Limit (POL) and various operating parameters to help the operator maintain plant operation within the limiting conditions for operation (LCO). Operating within the LCO guarantees that in the event of an Anticipated Operational Occurrence (AOO), the CPCs will provide a reactor trip in time to prevent unacceptable fuel damage.

The COLSS reserves the Required Overpower Margin (ROPM) to account for the Loss of Flow (LOF) and CEA misoperation transients. When the COLSS is Out of Service (COOS), the monitoring function is performed via the CPC calculation of DNBR in conjunction with Technical Specification COOS Limit Lines specified in the CORE OPERATING LIMITS REPORT which restricts the reactor power sufficiently to preserve the ROPM.

The reduction of the CEA deviation penalties in accordance with the CEAC (Control Element Assembly Calculator) sensitivity reduction program has been performed. This task involved setting many of the inward single CEA deviation penalty factors to 1.0. An inward CEA deviation event in effect would not be accompanied by the application of the CEA deviation penalty in either the CPC DNB and LHR (Linear Heat Rate) calculations for those CEAs with the reduced penalty factors. The protection for an inward CEA deviation event is thus accounted for separately.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

DOCKET NO. STN 50-530

PALO VERDE NUCLEAR GENERATING STATION, UNIT NO. 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 80
License No. NPF-74

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by the Arizona Public Service Company (APS or the licensee) on behalf of itself and the Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority dated January 5, 1996, as supplemented by letters dated April 19, 1996, May 1, 1996, and May 10, 1996, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C(1) and 2.C(2) of Facility Operating License No. NPF-74 are hereby amended to read as follows:

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 80, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective as of its date of issuance to be implemented within 30 days of the date of issuance, except for the pressurizer safety valve setpoints change which is to be implemented prior to startup from Unit 3 refueling outage six.

FOR THE NUCLEAR REGULATORY COMMISSION

WTRussell

William T. Russell, Director
Office of Nuclear Reactor Regulation

Attachments: 1. Page 4 of License
2. Changes to the Technical Specifications

Date of Issuance: May 23, 1996

Page 4 is attached, for convenience, for the composite license to reflect this change. Please remove page 4 of the existing license and replace with the attached page.

(1) Maximum Power Level

Arizona Public Service Company (APS) is authorized to operate the facility at reactor core power levels not in excess of 3876 megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 80, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. APS shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

(3) Antitrust Conditions

This license is subject to the antitrust conditions delineated in Appendix C to this license.

(4) Initial Test Program (Section 14, SER and SSER 2)

Any changes in the initial test program described in Section 14 of the FSARs (Palo Verde and CESSAR) made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

D. APS has previously been granted an exemption from Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR Part 50. This exemption was previously granted in Facility Operating License NPF-65 pursuant to 10 CFR 50.12.

With the granting of this exemption, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

E. The licensees shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Safeguard Contingency Plan is incorporated into the Physical Security Plan. The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Palo Verde

ATTACHMENT TO LICENSE AMENDMENT

AMENDMENT NO. 80 TO FACILITY OPERATING LICENSE NO. NPF-74

DOCKET NO. STN 50-530

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change. The corresponding overleaf pages are also provided to maintain document completeness.

REMOVE	INSERT
1-5	1-5
3/4 1-5	3/4 1-5
3/4 1-19	3/4 1-19
3/4 2-8	3/4 2-8
3/4 4-7	3/4 4-7
3/4 4-8	3/4 4-8
B 3/4 1-5	B 3/4 1-5
B 3/4 4-12	B 3/4 4-12

PHYSICS TESTS

1.21 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANAR RADIAL PEAKING FACTOR - F_{xy}

1.22 The PLANAR RADIAL PEAKING FACTOR is the ratio of the peak to plane average power density of the individual fuel rods in a given horizontal plane, excluding the effects of azimuthal tilt.

PRESSURE BOUNDARY LEAKAGE

1.23 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.24 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.25 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration, or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.26 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3876 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.27 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism.

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.4 The Reactor Coolant System lowest operating loop temperature (T_{cold}) shall be greater than or equal to 545°F.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{cold}) less than 545°F, restore T_{cold} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.4 The Reactor Coolant System temperature (T_{cold}) shall be determined to be greater than or equal to 545°F:

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System T_{cold} is less than 550°F.

#With K_{eff} greater than or equal to 1.0.

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE:

a. If only the spent fuel pool in Specification 3.1.2.5a. is OPERABLE, a flow path from the spent fuel pool via a gravity feed connection and a charging pump to the Reactor Coolant System.

b. If only the refueling water tank in Specification 3.1.2.5b. is OPERABLE, a flow path from the refueling water tank via either a charging pump, a high pressure safety injection pump, or a low pressure safety injection pump to the Reactor Coolant System.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and regulating) CEA drop time, from a fully withdrawn position, shall be less than or equal to 4 seconds from when the electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90% insertion position with:

a. T_{cold} greater than or equal to 550°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With the drop time of any full-length CEA determined to exceed the above limit, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time of full-length CEAs shall be demonstrated through measurement prior to reactor criticality:

a. For all CEAs following each removal and reinstallation of the reactor vessel head,

b. For specifically affected individual CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months.

SHUTDOWN CEA INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown CEAs shall be withdrawn to at least 144.75 inches.

APPLICABILITY: MODES 1 and 2*#.

ACTION:

With a maximum of one shutdown CEA withdrawn to less than 144.75 inches, except for surveillance testing pursuant to Specification 4.1.3.1.2, within 1 hour either:

a. Withdraw the CEA to at least 144.75 inches, or

b. Declare the CEA inoperable and comply with Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown CEA shall be determined to be withdrawn to at least 144.75 inches:

a. Within 15 minutes prior to withdrawal of any CEAs in regulating groups during an approach to reactor criticality, and

b. At least once per 12 hours thereafter except during time intervals when both CEAC's are inoperable, then verify the individual CEA positions at least once per 4 hours.

---

*See Special Test Exception 3.10.2.

#With K_{eff} greater than or equal to 1.

3/4.2.6 REACTOR COOLANT COLD LEG TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.2.6 The reactor coolant cold leg temperature (T_c) shall be within the Area of Acceptable Operation shown in Figure 3.2-1.

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With the reactor coolant cold leg temperature exceeding its limit, restore the temperature to within its limit within 2 hours or be in HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.2.6 The reactor coolant cold leg temperature shall be determined to be within its limit at least once per 12 hours.

*See Special Test Exception 3.10.4.
#With K_{eff} greater than or equal to 1

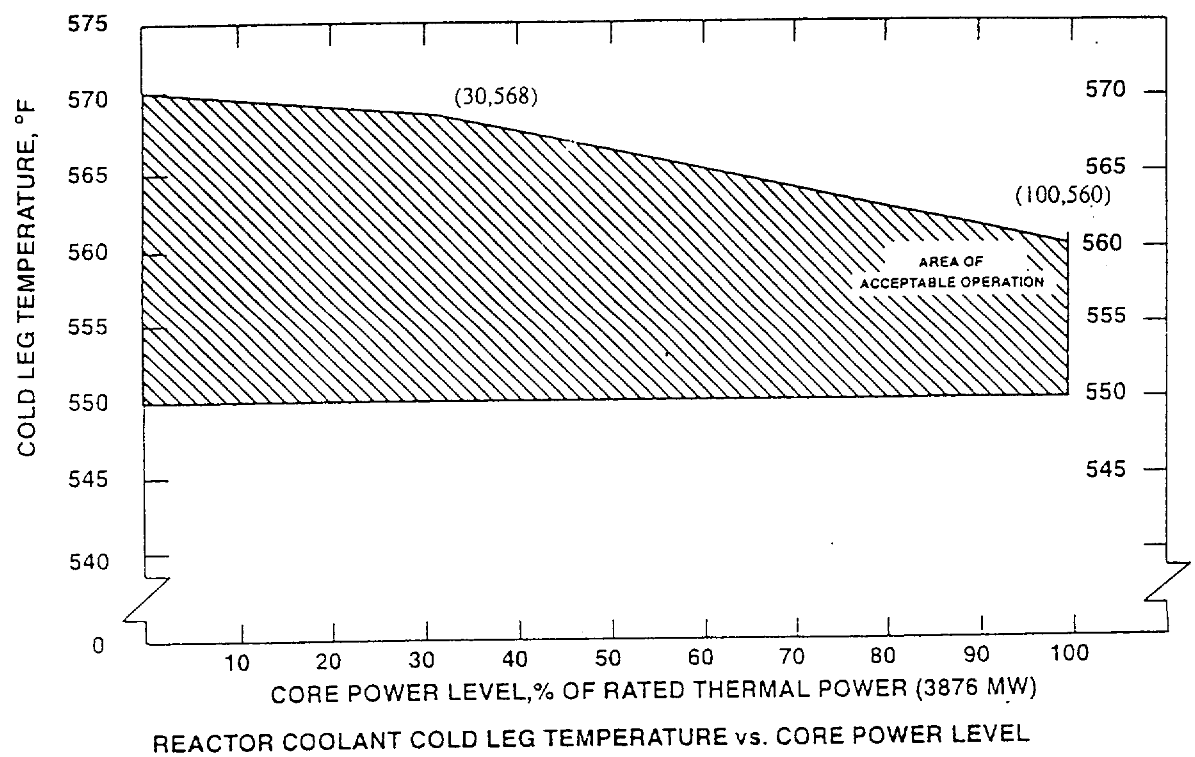

FIGURE 3.2-1

REACTOR COOLANT COLD LEG TEMPERATURE VS. CORE POWER LEVEL

REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer code safety valve shall be OPERABLE with a lift setting of 2475 psia +3, -1%*.

APPLICABILITY: MODE 4.

ACTION:

a. With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE shutdown cooling loop into operation.

b. The provisions of Specification 3.0.4 may be suspended for up to 12 hours for entering into and during operation in MODE 4 for purposes of setting the pressurizer code safety valves under ambient (HOT) conditions provided a preliminary cold setting was made prior to heatup.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer code safety valves shall be OPERABLE with a lift setting of 2475 psia +3, -1%*.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours with the shutdown cooling system suction line relief valves aligned to provide overpressure protection for the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional Surveillance Requirements other than those required by Specification 4.0.5.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

MOVABLE CONTROL ASSEMBLIES (Continued)

and LSSS setpoints determination. Therefore, time limits have been imposed on operation with inoperable CEAs to preclude such adverse conditions from developing.

Operability of at least two CEA position indicator channels is required to determine CEA positions and thereby ensure compliance with the CEA alignment and insertion limits. The CEA "Full In" and "Full Out" limits provide an additional independent means for determining the CEA positions when the CEAs are at either their fully inserted or fully withdrawn positions. Therefore, the ACTION statements applicable to inoperable CEA position indicators permit continued operations when the positions of CEAs with inoperable position indicators can be verified by the "Full In" or "Full Out" limits.

CEA positions and OPERABILITY of the CEA position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

The maximum CEA drop time restriction is consistent with the assumed CEA drop time used in the safety analyses. Measurement with T_{cold} greater than or equal to 550°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

Several design steps were employed to accommodate the possible CEA guide tube wear which could arise from CEA vibrations when fully withdrawn. Specifically, a programmed insertion schedule will be used to cycle the CEAs between the full out position ("FULL OUT" LIMIT) and 3.0 inches inserted over the fuel cycle. This cycling will distribute the possible guide tube wear over a larger area, thus minimizing any effects. To accommodate this programmed insertion schedule, the fully withdrawn position was redefined, in some cases, to be 144.75 inches or greater.

The establishment of LSSS and LCOs requires that the expected long- and short-term behavior of the radial peaking factors be determined. The long-term behavior relates to the variation of the steady-state radial peaking factors with core burnup and is affected by the amount of CEA insertion assumed, the portion of a burnup cycle over which such insertion is assumed and the expected power level variation throughout the cycle. The short-term behavior relates to transient perturbations to the steady-state radial peaks due to radial xenon redistribution. The magnitudes of such perturbations depend upon the expected use of the CEAs during anticipated power reductions

MOVABLE CONTROL ASSEMBLIES (Continued)

and load maneuvering. Analyses are performed based on the expected mode of operation of the NSSS (base load maneuvering, etc.) and from these analyses CEA insertions are determined and a consistent set of radial peaking factors defined. The Long Term Steady State and Short Term Insertion Limits are determined based upon the assumed mode of operation used in the analyses and provide a means of preserving the assumptions on CEA insertions used. The limits specified serve to limit the behavior of the radial peaking factors within the bounds determined from analysis. The actions specified serve to limit the extent of radial xenon redistribution effects to those accommodated in the analyses. The Long and Short Term Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 are specified for the plant which has been designed for primarily base loaded operation but which has the ability to accommodate a limited amount of load maneuvering.

The Transient Insertion Limits of Specifications 3.1.3.6 and 3.1.3.7 and the Shutdown CEA Insertion Limits of Specification 3.1.3.5 ensure that (1) the minimum SHUTDOWN MARGIN is maintained, and (2) the potential effects of a CEA ejection accident are limited to acceptable levels. Long-term operation at the Transient Insertion Limits is not permitted since such operation could have effects on the core power distribution which could invalidate assumptions used to determine the behavior of the radial peaking factors.

The PVNGS CPC and COLSS systems are responsible for the safety and monitoring functions, respectively, of the reactor core. COLSS monitors the DNB Power Operating Limit (POL) and various operating parameters to help the operator maintain plant operation within the limiting conditions for operation (LCO). Operating within the LCO guarantees that in the event of an Anticipated Operational Occurrence (AOO), the CPCs will provide a reactor trip in time to prevent unacceptable fuel damage.

The COLSS reserves the Required Overpower Margin (ROPM) to account for Loss of Flow (LOF) and CEA misoperation transients. When the COLSS is Out of Service (COOS), the monitoring function is performed via the CPC calculation of DNBR in conjunction with Technical Specification COOS Limit Lines specified in the CORE OPERATING LIMITS REPORT which restricts the reactor power sufficiently to preserve the ROPM.

The reduction of the CEA deviation penalties in accordance with the CEAC (Control Element Assembly Calculator) sensitivity reduction program has been performed. This task involved setting many of the inward single CEA deviation penalty factors to 1.0. An inward CEA deviation event in effect would not be accompanied by the application of the CEA deviation penalty in either the CPC DNB and LHR (Linear Heat Rate) calculations for those CEAs with the reduced penalty factors. The protection for an inward CEA deviation event is thus accounted for separately.

PRESSURE/TEMPERATURE LIMITS (Continued)

A typical LTOP system includes pressure relieving devices and a number of administrative and operational controls. Each of the Palo Verde Units has a similar LTOP system that includes two Shutdown Cooling System suction line relief valves for transient mitigation. Each relief valve has an opening setpoint of 467 psig which, in combination with certain other limiting conditions for operation contained in Technical Specifications, comprises the LTOP system.

Previously, the LTOP enable temperature during heatup and cooldown have been determined at the intersections between a horizontal line corresponding to the safety valve setpoint (2475 psia) and the most limiting P-T limit curves for heatup and cooldown, respectively. Note that the enable temperature generally identifies the upper temperature limit below which the LTOP system has to be operable.

In this analysis, the LTOP enable temperatures were determined in accordance with a definition contained in the latest revision of the Standard Review Plan 5.2.2. According to SRP 5.2.2 the LTOP enable temperature is "the water temperature corresponding to a metal temperature of at least RT_{NDT} + 90°F at the beltline location (1/4T or 3/4T) that is controlling in the Appendix G limit calculations." The heatup and cooldown rate limitations assure the limits of Appendix G to 10 CFR 50 will not be exceeded with overpressure protection provided by the primary safety valves. The various categories of load cycles used for design purposes are provided in Chapters 3 and 5 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so as not to exceed the limit lines of Figures 3.4-2a and 3.4-2b. This ensures that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 108 TO FACILITY OPERATING LICENSE NO. NPF-41,

AMENDMENT NO. 100 TO FACILITY OPERATING LICENSE NO. NPF-51,

AND AMENDMENT NO. 80 TO FACILITY OPERATING LICENSE NO. NPF-74

ARIZONA PUBLIC SERVICE COMPANY, ET AL.

PALO VERDE NUCLEAR GENERATING STATION, UNIT NOS. 1, 2, AND 3

DOCKET NOS. STN 50-528, STN 50-529, AND STN 50-530

1.0 INTRODUCTION

By application dated January 5, 1996, as supplemented by letters dated April 19, 1996, May 1, 1996, and May 10, 1996, the Arizona Public Service Company (APS or the licensee) requested changes to the facility operating license, and to the technical specifications (TSs) (Appendix A) to Facility Operating License Nos. NPF-41, NPF-51, and NPF-74, respectively for the Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3. The Arizona Public Service Company submitted this request on behalf of itself, the Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, El Paso Electric Company, Public Service Company of New Mexico, Los Angeles Department of Water and Power, and Southern California Public Power Authority. The proposed change would revise paragraph 2.C.(1) of the operating licenses and Section 1.26 of the TSs for each of the three PVNGS units to increase the authorized 100 percent reactor core rated thermal power (RTP) from 3800 megawatts thermal (MWt) to 3876 MWt, an increase of 2 percent.

To support the increased power operation, the proposed amendment would also revise TSs 4.1.1.4, 3.1.3.4, and 3.2.6 (Figure 3.2-1) to lower the allowable reactor coolant system cold-leg temperature limits for each of the three PVNGS units. Additionally, the licensee has proposed revising TSs 3.4.2.1 and 3.4.2.2 to lower the pressurizer safety valve setpoints by 25 psia for Units 1 and 3. The Unit 2 pressurizer safety valve setpoints were revised by Amendment 78, approved March 28, 1995, to the same value that is being requested for Units 1 and 3 in this application. The licensee indicated that lowering the pressurizer safety valve setpoints is not directly related to the power uprate; rather, it provides additional margin for steam generator tube plugging.

The April 19, 1996, May 1, 1996, and May 10, 1996, supplemental letters provided additional clarifying information and did not change the initial no significant hazards consideration published in the Federal Register on February 28, 1996 (61 FR 7544).

2.0 DISCUSSION

The licensee proposed to increase the rated thermal power of PVNGS Units 1, 2 and 3 by 2 percent with the proposed facility operating license and technical specification (TS) changes. The proposed increased rated thermal power (RTP) to 3876 MWt would require no plant modifications other than adjusting the core operating limit supervisory system (COLSS) setpoints for all three units.

The licensee performed analyses to support operation at the proposed RTP of 3876 for both the higher feedwater temperature (about 445°F) and a reduced feedwater temperature (about 425°F). This was done to give PVNGS management the option of operating at either temperature after the proposed power uprate license amendment has been approved. The decision whether to operate at the original design feedwater temperature or at the reduced temperature will depend on economic considerations such as electrical generation needs and the effect on steam generator (SG) life.

Operation at the reduced feedwater temperature results in better SG thermohydraulics but decreases megawatt output because of reduced thermodynamic efficiency.

Operation with the normal feedwater temperature results in poorer steam generator thermohydraulics. As a result, the dryout region of the SGs will increase slightly. However, the licensee modified the SGs to decrease hot-leg flow restrictions and introduce subcooled water into the tube bundle, and the subcooled water will improve the thermohydraulics of, and reduce the number of tubes in, the SG dryout region and so reduce the potential for stress corrosion cracking of the SG tubes.

The licensee also performed a 10°F reduction (to 611°F) in hot-leg temperature in 1994. The change was performed to minimize high temperatures and to reduce the potential for stress corrosion cracking in the hot-leg tubesheet area of the steam generators. The increase in RTP will be provided by a drop in cold-leg temperature of 1°F to maintain the current value for hot-leg temperature. The licensee concludes that the operating condition changes involved in the increased RTP are minimal. Increased RTP operation involves a change to operating setpoints of each unit and not a change in the design of the units.

Following this change, operation at 100 percent (3876 MWt RTP) will be achieved with three of the main turbine control valves full open, and the fourth valve approximately 90 percent open.

The licensee indicated that NRC approved codes and methods were used for analyzing the proposed power uprate. The licensee concluded that, based on the results of the safety analyses, the consequences of design basis events affected by the proposed power uprate are bounded by the current licensing basis except for the following events: loss of coolant accident, feedwater line break, steam generator tube rupture with loss of offsite power and fully stuck open atmospheric dump valve, and control element assembly (CEA) ejection. The licensee concluded that these four events are bounded by the current licensing basis, and do not exceed applicable regulatory limits.

In addition to analyzing design basis events, the licensee reviewed containment response, performed system reviews, and programmatic issues potentially affected by the proposed RTP increase. The licensee concluded that, based on these reviews, the design of the Palo Verde Units is adequate to support the proposed changes.

3.0 EVALUATION

APS and Asea Brown-Boveri Combustion Engineering (ABB-CE), the nuclear steam supply system vendor, evaluated Chapters 6 and 15 of the PVNGS Updated Safety Analysis Report (UFSAR) in support of the proposed 2 percent increase in RTP, reduced T_{cold}, and reduced pressurizer safety valve setpoint. The licensee stated that the safety analysis supporting this proposed amendment used a reactor core thermal power of 3954 MWt, which is 102 percent of the proposed rated thermal power of 3876 MWt. This is in accordance with Regulatory Guide 1.49, "Power Levels of Nuclear Power Plants," which requires that a 2-percent uncertainty in the power level measurement be included in the analysis. The licensee also indicated that the methodologies and assumptions used in performing the safety analyses in support of the proposed power increase were the same as those used in the previous analyses, and that NRC-approved codes and methods were used.

3.1 Emergency Core Cooling System (ECCS) Performance Analysis

3.1.1 Large-Break Loss-of-Coolant Accident (LBLOCA)

The licensee performed the LBLOCA ECCS performance analysis for the proposed increased RTP using the analytical method CENPD-132, Supplement 3-P-A, June 1985, "Calculative Methods for the CE Large Break LOCA Evaluation Model for the Analysis of CE and W Designed NSSS." This methodology was added to the list of NRC-approved methods in PVNGS TS Section 6.9.1.10.e. by Amendments 83, 70, and 55 for Units 1, 2, and 3, respectively (dated October 7, 1994).

The licensee stated that its analysis consisted of seven breaks in the reactor coolant pump discharge leg. These included both guillotine and slot breaks ranging in size from a full double-ended break to a 40 percent double-ended break. The reactor coolant pump (RCP) discharge leg was previously determined to be the limiting break location. It is limiting because both the core flow rate during blowdown and the core reflood rate are minimized for this location. Hot leg breaks and suction leg breaks were not analyzed because previous analyses have shown that these locations are not limiting.

As required by 10 CFR 50, Appendix K, paragraph I.C.1.b, at least three discharge coefficients were analyzed (full double-ended break, 80 percent and 60 percent). Because the 60-percent double-ended guillotine break resulted in the highest peak cladding temperature of the three discharge coefficients initially analyzed, a 40-percent double-ended break was analyzed to demonstrate that the maximum peak cladding temperature was achieved in the 0.6 double-ended guillotine break.

The licensee concluded that the limiting break of the PVNGS proposed power uprate LBLOCA ECCS performance analysis was determined to be the 60 percent double-ended guillotine break in the pump discharge (60 percent DEG/PD break). The two most significant changes are the increase in core power and the increase in the number of plugged tubes. These changes produced a blowdown hydraulic transient response that resulted in more stored energy remaining in the hot rod at the end of blowdown for the 60 percent DEG/PD break and, consequently, a higher peak cladding temperature during reflood.

3.1.2 Small-Break LOCA (SBLOCA)

The licensee performed the SBLOCA ECCS performance analysis using the NRC-approved ABB-CE SBLOCA evaluation model for core rated thermal power of 3876 MWt (plus a 2 percent uncertainly). The same methodology was used in the previous PVNGS SBLOCA ECCS performance analysis for a rated core power of 3800 MWt (plus a 2 percent uncertainty).

The licensee indicated that four reactor coolant pump discharge leg breaks, ranging in size from 0.01 ft^2 to 0.07 ft^2, were analyzed. The reactor coolant pump discharge leg was previously determined to be the limiting break location because it maximizes the amount of spillage from the safety injection system.

The licensee also indicated that break sizes larger than 0.07 ft^2 were not analyzed because these breaks are sufficiently large to depressurize the reactor coolant system (RCS). Once the RCS is depressurized, the injection from the safety injection tanks (SITs) would terminate the heatup of the cladding. The PVNGS Cycle 1 Final Safety Analysis Report (FSAR) SBLOCA spectrum analysis demonstrated that (1) such break sizes have peak cladding temperatures that are hundreds of degrees less than that of the limiting SBLOCA break size, and (2) the limiting SBLOCA break size is one wherein the peak cladding temperature is calculated to occur when the only injection is from the high-pressure safety injection pumps.

In addition to the four discharge leg breaks, the licensee analyzed a 0.03 ft^2 break in the top of the pressurizer (0.03 ft^2 represents the area of a fully open pressurizer safety valve).

The licensee stated that analysis of a spectrum of sizes ranging from 0.01 ft^2 to 0.07 ft^2 provides assurance that the most limiting SBLOCA is covered. The break size range of 0.01 ft^2 to 0.07 ft^2 covers the range of break sizes that experience partial uncovering of the core and subsequent cladding heatup that is terminated solely by injection from the high pressure safety injection (HPSI) pump. The analysis of the 0.01 ft^2 break showed no core uncovery. Therefore, breaks smaller than 0.01 ft^2 will also not experience any uncovery. The analysis of the 0.07 ft^2 break showed that the SITs began to inject late in the transient after injection from the HPSI pump had terminated the cladding heatup. Breaks larger than 0.07 ft^2 will depressurize faster, resulting in earlier injection from the SITs and, consequently, lower peak cladding temperatures. This was demonstrated in the CESSAR FSAR SBLOCA spectrum analysis, which became the break spectrum analysis for PVNGS Cycle 1.

The peak cladding temperatures from the Cycle 1 analyses for the 0.20, 0.35, and 0.5 ft^2 breaks were all calculated to occur shortly after injection from the SITs began. The peak cladding temperature for the 0.05 ft^2 break was calculated to occur prior to the initiation of flow from the SITs.

Based on the above, the licensee concluded that the 0.05 ft^2 break size with a peak cladding temperature of 1970°F was the limiting SBLOCA break size. This peak cladding temperature is less than the 10 CFR Part 50 acceptance criteria of 2200°F.

3.1.3 Post-LOCA Long-Term Cooling (LTC)

The licensee performed the post-LOCA LTC analysis using ABB-CE's NRC-approved evaluation model. The same methodology was used in the previous PVNGS LTC analysis performed at the current rated core power of 3800 MWt. The licensee stated that the objective of the analysis was to demonstrate, for a complete spectrum of break sizes, that (1) core decay heat is removed in the long term while the core temperature is maintained at an acceptably low value, and (2) the boric acid concentration in the core is maintained below its solubility limit.

The licensee's analysis demonstrated that core decay heat can be removed over the long term for a complete spectrum of break sizes. For breaks smaller than 0.03 ft^2, core decay heat removal can be accomplished by initiating and maintaining shutdown cooling. For breaks larger than 0.006 ft^2, core decay heat removal can be accomplished by maintaining simultaneous hot- and cold-leg high-pressure safety injection. The overlap in these break sizes is the range within which either the large- or small-break cooling procedures could be successfully performed. The analysis determined that more than 13 hours is required to exhaust all auxiliary feedwater during a cooldown of the RCS. This gives the operator ample time to determine, and begin using, the appropriate long-term decay heat removal method.

The licensee indicated that the analysis for the proposed RTP increase demonstrated that the boric acid concentration in the core is maintained below its solubility limit if a minimum high-pressure safety injection flow of 380 gpm is begun to both the hot and cold side of the RCS between 2 and 3 hours after the start of the LOCA. This is 20 gpm more than the minimum required flow rate of 360 gpm for the previous analysis at a rated core power of 3800 MWt. UFSAR Section 6.3.3.4.1 describes the 2-3 hour safety injection (SI) delay assumed in the previous analysis. TS Surveillance Requirement 4.5.2.h for each of the PVNGS units requires a minimum flow well in excess of the 380 gal/min hot- and cold-side flow needed to meet the safety analysis requirement for operation at the proposed increased RTP. (TS 4.5.2.h requires, for simultaneous hot and cold leg injection, 525 gpm hot leg flowrate and 525 gpm sum of cold leg flowrates).

3.1.4 Conclusions

The licensee performed an ECCS performance analysis for PVNGS Units 1, 2, and 3 for a spectrum of break sizes ranging from a full double-ended guillotine break to a 0.01 ft^2 break in the reactor coolant pump discharge leg. The licensee determined that the limiting break size (the break size that resulted in the highest peak cladding temperature) was the 60-percent DEG/PD break.

The licensee concluded that the results of the analysis demonstrate conformance to 10 CFR 50.46 ECCS acceptance criteria at a proposed rerated core power of 3876 MWt and a peak linear heat generation rate (PLHGR) of 13.5 kw/ft. The licensee's conclusion is presented below:

(1) "Peak cladding temperature. The calculated maximum fuel element cladding temperature shall not exceed 2200°F."

Result: The ECCS performance analysis calculated a peak cladding temperature of 2165°F.

(2) "Maximum cladding oxidation. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation."

Result: The ECCS performance analysis calculated a maximum cladding oxidation of 0.079 times the total cladding thickness before oxidation.

(3) "Maximum hydrogen generation. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react."

Result: The ECCS performance analysis calculated a maximum hydrogen generation of less than 0.0086 times the hypothetical amount.

(4) "Coolable Geometry. Calculated changes in core geometry shall be such that the core remains amenable to cooling."

Result: The cladding swelling and rupture model of the ABB-CE LBLOCA evaluation model accounts for the effects of changes in core geometry that would occur if cladding rupture is calculated to occur. Adequate core cooling was demonstrated for the changes in core geometry that were calculated to occur as a result of cladding rupture. In addition, the transient analysis was performed until cladding temperatures decreased and the RCS was depressurized, thereby precluding any further cladding deformation. Therefore, a coolable geometry was demonstrated.

(5) "Long-term cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended

period of time required by the long-lived radioactivity remaining in the core."

Result: The post-LOCA long-term cooling analysis demonstrated long-term decay heat removal with an acceptably low core temperature for a complete spectrum of break sizes.

The NRC staff has previously approved the evaluation model used in the licensee's ECCS analysis. The staff has reviewed the licensee's submittals and has concluded that it shows the plant to be in compliance with 10 CFR 50.46 and Appendix K to 10 CFR Part 50 for the proposed power uprate conditions. The PVNGS ECCS is, therefore, acceptable for operation at the proposed rerate conditions.

3.2 Containment Response Analyses

3.2.1 Loss-of-Coolant Accident (LOCA)

The licensee stated that the containment pressure and temperature response following an LBLOCA inside containment was reanalyzed for the proposed rerated core thermal power analysis performed to 3954 MWt (102 percent of 3876 MWt). The LOCA event is characterized by four distinct phases. These phases are blowdown, reflood, post-reflood, and long-term cooldown. The mass and energy release analyses were performed by ABB-CE with the CEFLASH-4A and FLOOD3 codes. These are the NRC-approved codes used in the original Palo Verde design analyses. The limiting peak pressure case of the double-ended discharge leg slot break (DEDLSB) with maximum safety injection flow was analyzed. This case is the UFSAR limiting case for containment peak pressure, as previously presented in UFSAR Section 6.2.1.1.3.1.

The licensee also stated that the pressure and temperature response of the containment was analyzed using the Bechtel COPATTA code as described in UFSAR Section 6.2.1.1.3.1. One train of containment spray at the minimum TS containment spray flow was modeled in the analysis. In addition, decay heat for long-term cooldown analysis was modeled using the 1979 ANS 5.1 Standard plus a two sigma uncertainty. The analysis resulted in a peak containment pressure of 48.9 psig, which is less than the current UFSAR Section 6.2.1.1.3.1 pressure of 49.5 psig and the containment design pressure of 60 psig. Containment pressure is reduced to 17.1 psig (24 hours), which is less than 50 percent of the calculated maximum value as specified in the Standard Review Plan, NUREG-0800.

Relative to the original FSAR LOCA, the power uprate analysis utilized reduced values for SG inventory (including main feedwater addition), secondary metal energy, and secondary to primary heat transfer. These values were determined through updated and more precise calculations relative to the bounding values assumed in the original FSAR cases. These reduced values translated into less secondary side stored energy. This reduced the energy contribution to the primary side break flow, leading to a less severe peak containment pressure. Thus, for the limiting discharge leg slot break maximum SI LOCA case, the power uprate secondary side inputs played a significant role in reducing the peak containment pressure.

The staff has reviewed the licensee's submittals and has concluded that the licensee has adequately demonstrated that the containment will satisfy its design functions under the proposed rerate conditions and is, therefore, acceptable.

3.2.2 High Energy Line Break (HELB)

The licensee reanalyzed main steamline break (MSLB) events inside and outside containment at the proposed increased core rated thermal power conditions (plus a 2 percent uncertainty). Sensitivity analyses were performed to address both peak pressure (discussed in this section of this safety evaluation) and equipment qualification (EQ) (discussed in Section 3.3 of this safety evaluation). The analyses incorporated the effects of steam superheating following uncovery of the steam generator tube bundle in accordance with NRC Information Notice (IN) 84-90, "Main Steam Line Break Effect on Environmental Qualification of Equipment," and IN 93-55, "Potential Problem with Main Steam Line Break Analysis for Main Steam Vaults/Tunnels." ABB-CE performed the MSLB mass and energy releases using the NRC-approved SGNIII code. This code was also used for the original PVNGS design analyses.

The licensee evaluated MSLB cases inside containment at initial reactor power levels of 102 percent, 75 percent, 50 percent, and 0 percent of 3876 MWt (the proposed uprated condition) to determine the pressure and temperature responses for the containment structure. The limiting single failure of a loss of one cooling train was included in the analyses. The 102 percent case yielded the highest peak temperature condition (393°F at 84 seconds), and the 0 percent case yielded the highest peak pressure condition (38.8 psig at 182 seconds). The licensee concluded that these conditions remain bounded by previous analyses (399°F as listed in UFSAR Table 6.2.1-10.E for peak temperature and 41.8 psig as listed in UFSAR Table 6.2.1-10.D for peak pressure).

The licensee also evaluated the affects of the proposed RTP increase on HELB scenarios outside containment and, with the exceptions of environmental qualification considerations (discussed in Section 3.3 of this safety evaluation) and structural pressurization, found that the HELB scenarios were bounded by previous analyses. In the case of structural pressurization, the licensee determined that feedwater line break is the bounding case yielding a new peak pressure of 16 psig, which is less than the main steam support structure (MSSS) design pressure of 21 psig.

The staff has reviewed the information provided by the licensee. Since the affects of the proposed RTP increase on HELB scenarios inside and outside containment either remain bounded by previous analyses or (in the case of structural pressurization where the previous analysis was not bounding) do not cause structural design limits to be exceeded, the staff finds that HELB considerations do not pose a safety problem for a proposed 2 percent RTP increase.

3.3 Equipment Qualification

The licensee's submittal of January 5, 1996, and the supplementary information that was provided by the submittals of April 19 and May 1, 1996, discuss the effects of the proposed 2-percent RTP increase on the environmental qualification (EQ) of plant equipment. In general, the Category I criteria contained in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," was used by the NRC staff at the time of licensing to assess the adequacy of EQ at Palo Verde. However, in its Safety Evaluation Report of November 1981, the NRC staff did allow the licensee to assume 8 percent re-vaporization in analyzing the design basis main steam line break inside containment which is a NUREG-0588 Category II criteria. These same criteria were used by the licensee in evaluating the effects of the proposed 2 percent increase in RTP on EQ. The licensee's revised analyses also included the effects of steam superheating following uncovery of the steam generator tube bundle; a smaller usable volume was assumed for the refueling water storage tank to account for level measurement inaccuracies; and containment pressure was assumed to be 2.5 psig (instead of 0 psig) in order to conservatively bound allowed operating conditions.

The licensee's submittals indicate that the revised EQ temperature and pressure profiles inside containment due to MSLB and LOCA events are very similar to the previous profiles. Consistent with Section 6.2.1 of the licensee's UFSAR, the MSLB was found to produce the peak containment temperature and the LOCA produced the peak containment pressure. The MSLB analysis for the increased RTP, including the effects of steam superheat after steam generator tube bundle uncovery, resulted in a peak containment temperature approximately 7°F higher than the current licensing basis peak temperature of 368°F. The revised LOCA temperature profile was found to be only slightly elevated during the latter stages of cooldown. As before, the licensee found that the revised LOCA profile was more limiting than the MSLB profile relative to containment pressure. The licensee concluded that because the revised analyses used an initial containment pressure of 2.5 psig, the peak pressure increased by that amount to 52 psig which is less than the containment design pressure of 60 psig.

To address conditions outside containment, the licensee revised the MSLB and the feedwater line break (FWLB) analyses for the MSSS. As was the case in the previous analyses, the revised analyses showed that the MSLB is bounding for establishing the temperature profile. The licensee's submittals indicate that during a MSLB at 0 percent power, temperature in the MSSS reaches a new peak of 383°F as compared to the previous peak of 300°F; but that the new peak is of very short duration, with the revised profile exceeding the previous one for a total of about four minutes while the temperature climbs to the new peak and then rapidly decreases below 300°F. This compares to the previous profile which rises quickly to 300°F and remains there for 15 minutes. Likewise, the licensee's submittals indicate that during a MSLB from 3954 MWt (increased RTP plus 2 percent), temperature in the MSSS peaks at 373°F. While this is somewhat lower than the peak that is reached during a MSLB from 0 percent power, the licensee has determined that this is the controlling profile for EQ purposes in the MSSS since it is of longer duration and has a greater influence on component temperatures. With regard to pressure in the MSSS, the licensee found that the revised pressure profile peaks at 1 psig which is less severe than the previous profile and is therefore bounded by the earlier analyses.

The staff noted that in the HELB discussion (Section 3.2.2 of this safety evaluation), the licensee indicated that pressure would reach 16 psig in the MSSS, and questioned why this higher pressure was not applicable to EQ. During a conference call on May 7, 1996, the licensee stated that all the feedwater piping in the MSSS satisfied the break exclusion criteria listed in SRP Section 3.6.2 and for EQ purposes, SRP Section 3.6.1 only required that the licensee consider a longitudinal break with a cross-sectional area of at least 1 square foot. However, the licensee assumed a double-ended guillotine break of the exclusion area piping to satisfy other staff criteria for impingement and dynamic loading of the structure. The staff found that the licensee's explanation was consistent with the SRP requirements and past licensing review practices, and had no further questions on this matter.

The licensee's submittals indicate that all equipment in the EQ program was reviewed against the revised temperature and pressure profiles to assure that equipment would remain qualified under the increased RTP conditions. Where previous EQ profiles were exceeded, the licensee performed further review and analyses as allowed by NUREG-0588 Category I criteria to demonstrate that EQ equipment continued to be qualified under the revised profiles. The licensee also compared the revised 180-day integrated radiation dose for the power uprate conditions with the integrated radiation dose that was used previously and determined that the dose would increase by about 0.2 percent. The licensee determined that this small increase in dose would not result in any equipment becoming unqualified. Given these considerations, the staff finds that the licensee has established sufficient assurance that equipment qualification is adequate for the proposed RTP increase and that EQ will be maintained in accordance with the licensing basis of the plant, as discussed and modified in this section of the safety evaluation.

3.4 Non-LOCA Transient Analyses

The licensee performed a reanalyses of all Chapter 15 UFSAR events to evaluate the effects of the proposed RTP increase, T_{cold} decrease, and pressurizer safety valve setpoint decrease for PVNGS. The licensee stated that the same NRC approved mathematical models and computer codes were used in the non-LOCA safety analysis as in previous analyses. The CESEC-III computer code was used to simulate overall NSSS behavior for the non-LOCA events, and the CETOP-D computer code to simulate the fluid conditions within the hot channel of the reactor core and calculate the departure from nucleate boiling ratio (DNBR).

The licensee also indicated that the same analytical methodology was used as in previous PVNGS reloads. The setting of COLSS and core protection calculator (CPC) constants to preserve thermal margin and to maintain specified acceptable fuel design limits (SAFDLs) for anticipated operational occurrence (AOOs) (margin-setting events) is performed on a reload-specific basis and thus is not completed until just before each reload, when the physics parameters from the previous cycle are known. The licensee stated that Unit 1 will include the proposed increased RTP and associated TS changes in the bases for the safety analyses for the next refueling cycle. The Unit 1 COLSS and CPC constraints will be calculated and implemented prior to startup from the Unit 1 refueling outage 6 when the increased RTP is scheduled for implementation. Unit 2 incorporated the increased RTP changes in the COLSS and CPC analyses during the refueling outage just completed. These COLSS and CPC constants were verified to be conservative for operation at 3800 MWt prior to startup from the refueling outage. The COLSS and CPC analyses for Unit 3 have been reviewed and reanalyzed to incorporate the increased RTP changes. The Unit 3 COLSS and CPC constant changes necessary for increased RTP have been prepared and will be installed prior to implementation of increased RTP. Thus the COLSS and CPC constants necessary for margin setting events have been installed for Unit 2, and are ready to be implemented in Unit 3 prior to implementing the increased RTP.

Since the proposed amendment would be initially implemented in Unit 3 without lowering pressurizer safety valve (PSV) setpoints, the licensee analyzed pressure-peaking events. By letter dated May 1, 1996, the licensee indicated that additional analyses were performed using a more negative moderator temperature coefficient. The analyses showed that a more negative moderator temperature coefficient provides adequate compensation for not lowering the PSV setpoints and that the peak pressures of affected events met the applicable acceptance criteria. The staff questioned when the moderator temperature coefficient (MTC) would be measured in Unit 3. The licensee replied that the Unit 3 Cycle 6 MTC was measured on January 14, 1996, at 100 percent power and 43.5 effective full power days burnup using surveillance test procedure 72ST-9RX02. The measured value was -1.210×10^{-4} delta rho/°F, the predicted value was -1.191×10^{-4} delta rho/°F (corrected for differences in predicted and actual conditions). As burnup increases, this value will become more negative. This measured value is more negative than that utilized in the Unit 3 analyses to justify operation at the proposed increased rated thermal power without a reduction in the pressurizer safety valve setpoint (mid-cycle implementation of power uprate). The completion of this test satisfied the commitment to verify by measurement that the MTC in Unit 3 is more negative than the value assumed in the safety analyses prior to implementation of the proposed RTP increase.

Following is a summary of the results of the licensee's review and reanalysis of non-LOCA transients, along with the NRC staff findings.

3.4.1 Increased Heat Removal Event (UFSAR 15.1)

3.4.1.1 Moderate Frequency Events

The licensee concluded that increased main steam flow events establish the bounding conditions for all of the other events that fall in this category. The licensee's submittals indicated that the need to examine a spectrum of increased main steam flow events is considered during the reload analysis for each core to ensure that the CPC digital filters provide a conservative calculation of DNBR. The licensee stated that this process has been completed for PVNGS Units 2 and 3 reactor cores, and that it will be completed for the Unit 1 core as part of the Cycle 7 reload analysis. Based on the information contained in the licensee's submittals, the staff concluded that the licensee has adequately addressed moderate frequency increased heat removal events for the proposed RTP increase.

3.4.1.2 Infrequent Events

The licensee concluded that the inadvertent opening of an atmospheric dump valve with single failure establishes the bounding conditions for events that fall in this category. The licensee stated that the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) in combination with a loss of offsite power (LOP) was analyzed as an upper bound of the severity of the combination of an AOO with a single failure. The licensee has determined that this is the limiting event, as the IOSGADV results in dryout of one steam generator and provides a direct release path for radionuclides and the LOP procedures the most rapid degradation of thermal margin of all potential single failure scenarios.

The licensee stated that the choice of loss of offsite power as a single failure is consistent with the licensee's UFSAR Section 15.1.4.1. As stated in UFSAR Section 15.1.4.1, an evaluation of single failures shows that the limiting single failure for the events of this section is the loss of offsite power concurrent with a turbine trip. The LOP is assumed to occur at a point in the transient when the minimum hot channel DNBR is just above that which would cause the core protection calculators to initiate a reactor trip signal on low DNBR. The DNBR is thus at the lowest possible pretrip value. The loss of flow due to the four pump coastdown, which results from the assumption of LOP following a turbine trip, causes a greater decrease in DNBR after a reactor trip than other possible single failures. None of the other single failures can cause a significant change in DNBR in the time interval between the start of the flow coastdown and the time at which core heat flux begins to decrease due to CEA insertion. Therefore, the event plus a single failure presented is the IOSGADV + LOP. In addition to the assumed single failure of loss of offsite power, it is assumed that the most reactive CEA is held in the fully withdrawn position following a reactor trip.

The licensee also stated that IOSGADV with LOP was modeled assuming that the initiating excess load type event would degrade the initially preserved thermal margin until the core is just above the DNBR SAFDL as calculated by the CPCs. The LOP was then assumed to occur when the reactor was about to trip. The LOP results in a coastdown of the reactor coolant pumps. This RCP coastdown is the single failure which results in the fastest degradation of the thermal margin of the core.

The RCS coolant flow coastdown resulting from the LOP is an input into the HERMITE code. The input was calculated by the COAST computer code and accounts for the proposed power uprate condition, the reduction of the core inlet temperature, and up to 3000 total plugged tubes with an asymmetry of 1000 plugged tubes. The input is also adjusted for the braking effect of the other electrical loads on the busses after an LOP.

The time of the CPC low DNBR trip is calculated based upon the flow coastdown, and the CEA motion is specified in the HERMITE model. The time of minimum DNBR and the conditions at the time of minimum DNBR are determined with the CETOP computer code via linkage from the HERMITE simulation. The number of pins in DNB is determined from the DNBR values via the statistical convolution method. All pins actually predicted to experience DNB are conservatively assumed to have clad failure.

The 2-hour site boundary dose is determined based upon the conservative release path assumptions of the IOSGADV with LOP, including the assumption that the affected SG dries out because of continued steaming through the stuck-open valve.

The licensee further stated that the minimum DNBR is seen to be reached at 2.05 seconds. The extent of predicted fuel pin failure is calculated by the statistical convolution method. For PVNGS Unit 2 Cycle 7, less than 1.92 percent of the fuel pins experience DNB, which results in a calculated 2-hour site boundary dose of 30 rem. In a submittal dated January 5, 1996, the licensee stated that the results of the IOSGADV with LOP event analyses demonstrate that the entire class of AOOs with single failure will have results within approved limits for operation of PVNGS Unit 2 and Unit 3 for the increased RTP conditions. The licensee indicated that this analysis will be completed for Unit 1 during the Cycle 7 reload analysis.

3.4.1.3 Limiting Faults

3.4.1.3.1 Hot Full Power (HFP) Post-Trip Steamline Break (SLB) With and Without LOP

The licensee stated that the analysis of the post-trip return-to-power steamline break showed that the core remains subcritical and that the power generated in the increase in subcritical multiplication due to the RCS cooldown is insufficient to cause the SAFDLs to be approached.

Four scenarios were considered for the return-to-power SLB:

Hot Zero Power with LOP
Hot Zero Power with AC Available
Hot Full Power with LOP
Hot Full Power with AC Available

The licensee asserted that the return-to-power SLB analyses performed originally for PVNGS and for subsequent reloads have shown that the maximum cooldown, and therefore the greatest potential for a return-to-power, results from cases with a LOP. The small increase in core power and 2°F reduction in allowable cold leg temperature would not change the relative severity of the scenarios, hence the licensee explicitly analyzed and presented the LOP cases in detail.

The licensee stated that there are two most limiting post-trip SLB events for the Palo Verde units. These events are the large steamline break during full power operation with concurrent loss of offsite power (SLBFPLOP) and the large steamline break during zero power operation with concurrent loss of offsite power (SLBZPLOP).

The licensee stated that the calculated maximum results show that for a large SLB at full or zero power with LOP, there is no post-trip return to power. Thus the SAFDLs on DNB and linear heat generation rate (LHGR) are not challenged. The peak pressures of the RCS and steam generators are below the design limits since the pressure decreases throughout the event.

The licensee stated that the results of the post-trip steamline break event analysis for operation of PVNGS Unit 2 Cycle 7 at the proposed increased RTP of 3876 MWt are within those of the previous analysis.

The post-trip steam line break event analysis was performed for power uprate operation for Unit 2 Cycle 7 and Unit 3 Cycle 6 midcycle implementation. The safety analysis for Unit 1 Cycle 7 will be reviewed at the power uprate conditions during the Cycle 7 reload analysis to ensure that the consequences are bounded by the analysis of record. Future cycle operation will be verified on a cycle specific basis during each cycle's reload safety analysis.

3.4.1.3.2 HFP Pre-Trip Steamline Break

The licensee stated that the analysis demonstrated that sufficient initial thermal margin will be preserved by COLSS and the TS limiting conditions for operation (LCOs) to ensure that the SAFDLs are not violated during the power excursion pre-trip SLB. The current pre-trip SLB in the UFSAR show a small number (<0.7 percent) of pins experiencing DNB. The licensee stated that to ensure that SAFDLs are not violated, appropriate conservatism will be incorporated in COLSS databases in each of the PVNGS units before the increased RTP changes are implemented.

3.4.2 Decreased Heat Removal Events (UFSAR 15.2)

3.4.2.1 Moderate Frequency and Infrequent Events

The licensee concluded that the inadvertent opening of an atmospheric dump valve with single failure establishes the bounding conditions for events that fall in this category. The licensee analyzed a loss of condenser vacuum (LOCV) that may occur because of the failure of the circulating water system to supply cooling water, failure of the main condenser evacuation system to remove noncondensable gases, or excessive in-leakage of air through a turbine gland. The turbine is assumed to trip immediately when condenser vacuum is lost.

The licensee concluded that the maximum RCS pressure will not exceed 2742 psia during a LOCA event. This pressure is less than the allowable maximum system pressure of 2750 psia (110 percent of design) and is thus acceptable. The licensee also concluded that the secondary pressure would not exceed 1371 psia during this event. This pressure is less than the maximum allowable system pressure of 1397 psia (110 percent of design) and is thus acceptable.

To implement the proposed increase in RTP in the middle of the Unit 3 operating cycle after May 1, 1996, the licensee analyzed the LOCV event for Unit 3 using the existing pressurizer safety valve setpoint of 2500 psia (rather than the amendment requested setpoint of 2475 psia). The licensee's analysis used a negative moderator temperature coefficient of -1.0 x 10^{-4} delta rho per degree Fahrenheit, which is more positive (conservative) than the value measured in Unit 3. The analysis resulted in a peak RCS pressure of 2736 psia, which is less than the allowable peak primary system pressure of 2750 psia. The peak secondary pressure was 1371 psia, which is less than the allowable pressure for this event of 1397 psia.

The licensee stated that this analysis and other pressure-peaking event analyses (i.e., the feedwater line break) demonstrate that the measured negative temperature coefficient in Unit 3 (which has been verified by testing) provides sufficient mitigative effect to implementing the RTP increase and T_{cold} decrease for the duration of the current operating cycle without reducing the pressurizer safety valve setpoint. The reduced pressurizer safety valve setpoint changes will be implemented in Unit 3 during the next refueling outage.

The loss of condenser vacuum analysis results was performed for power uprate operation for Unit 2 Cycle 7 with the pressurizer safety valve setpoint of 2475 psia and the moderator temperature coefficient (MTC) as specified in the unit's Core Operating Limits Report (COLR) as referenced in the technical specifications. A special assessment was performed to support mid-cycle implementation in Unit 3 with pressurizer safety valve setpoint of 2500 psia and MTC of -1.0E^{-4} delta rho per degree Fahrenheight or more negative. The Unit 3 MTC has been confirmed to be more negative than this value, as stated in the April 19, 1996 letter. The safety analysis for Unit 1 Cycle 7 will be reviewed at the power uprate conditions and the moderator temperature coefficient (MTC) as specified in the unit's Core Operating Limits Report (COLR) as referenced in the Technical Specifications during the Cycle 7 reload analysis to ensure that the consequences are bounded by the analysis of record. Future cycle operation will be verified on a cycle specific basis during each cycle's reload safety analysis.

3.4.2.2 Limiting Faults

The licensee analyzed two types of feedwater line break (FWLB) events for the Palo Verde Unit 2 Cycle 7 at 3876 MWt: the feedwater pipe break with coincident loss of offsite power (UFSAR 15.E.4) and the feedwater pipe break with failure of two reactor coolant pumps to fast transfer from onsite power to offsite power when a reactor trip occurs (UFSAR 15.E.5). For both types of FWLB events, the pipe break is assumed to occur in the downcomer line between the steam generator and its associated feedwater line check valve. A limiting break size of 0.2 ft^2, which was determined to produce peak RCS pressure, was analyzed (UFSAR Section 15.E.3). The two FWLB events involve similar increases in primary pressure, secondary pressure, and pressurizer liquid volume.

The licensee stated that the analysis of a FWLB event with coincident loss of offsite power is regarded as a large FWLB event with the 0.2 ft^2 being the lower limit of the spectrum of large-break sizes. The licensee also stated that a large FWLB event causes a loss of subcooled feedwater to both steam generators. When feedwater is lost, the steam generator temperatures increase and liquid inventories decrease. The increasing secondary side temperatures reduce the primary-to-secondary heat transfer and force a heatup and pressurization of the RCS. The RCS heatup and pressurization become more severe as the ruptured steam generator, losing inventory through the break, continues to lose its heat transfer capability. A reactor trip on high pressurizer pressure protects against this event. After a reactor trip, the core heat rate falls to match the heat removal capability of the intact steam generator.

The licensee stated that the analysis of a FWLB event with failure of two RCPs to fast transfer is regarded as a small FWLB event with the 0.2 ft^2 as the upper limit of the spectrum of small-break sizes. The licensee stated that a small FWLB event progresses like an FWLB event with coincident loss of offsite power. However, the primary-to-secondary heat transfer degradation is less severe and consequently results in a lower peak RCS pressure.

The licensee indicated that the maximum RCS pressure calculated for a large FWLB event for Palo Verde Unit 2 Cycle 7 was 2810 psia, which is below the current UFSAR large FWLB event value of 2843 psia. The peak steam generator pressure was calculated to be 1347 psia. The licensee concludes that the maximum steam generator pressure is slightly higher than the current UFSAR value of 1318 psia, but is significantly lower than the limiting criterion of 1397 psia, which is 120 percent of the steam generator design pressure.

The maximum RCS pressure and steam generator pressure calculated for a small FWLB event for Palo Verde Unit 2 Cycle 7 were 2626 psia and 1329 psia, respectively, which do not exceed the currently small FWLB event values of 2712 psia and 1342 psia.

The licensee further stated that operation of Palo Verde Unit 2 Cycle 7 at the proposed rated power of 3876 MWt will yield results for a large or small FWLB event within the previously reviewed and approved limits. The maximum RCS and steam generator pressures are sufficiently low in comparison to the limiting criteria to ensure that a radiological dose produced by a large or small FWLB event would be within the 10 CFR Part 100 limits. The minimum DNBR remains above the SAFDL, indicating that no fuel cladding failure occurs.

The licensee also analyzed this event for Unit 3 with a pressurizer safety valve setpoint of 2500 psia and an MTC of -1.0 x 10-4 delta rho per degree Fahrenheit to support the implementation of the proposed increased RTP in midcycle. The licensee stated that the peak RCS pressures is 2761 psia for a large feedwater line break and 2630 psia for a small feedwater line break.

The steam generator pressures were 1315 and 1327 psia, respectively, which are less than the acceptance criteria for the events. The licensee stated that this demonstrates that the mitigative effects of the more negative MTC which exists in Unit 3, would support midcycle implementation of the proposed increased RTP without the need to reduce the pressurizer safety valve setpoints until the next refueling outage (See Section 3.4 MTC test results for Unit 3).

The feedwater line break event analysis was performed for power uprate operation for Unit 2 Cycle 7 with the pressurizer safety valve setpoint of 2475 psia and the moderator temperature coefficient (MTC) as specified in the Unit's Core Operating Limits Report (COLR) as referenced in the Technical Specifications. A special assessment was performed to support mid-cycle implementation in Unit 3 with pressurizer safety valve setpoint of 2500 psia and MTC of -1.0E-4 delta rho per degree Fahrenheight or more negative. The Unit 3 MTC has been confirmed to be more negative than this value, as stated in the April 19, 1996 letter. The safety analysis for Unit 1 Cycle 7 will be reviewed at the power uprate conditions and the moderator temperature coefficient (MTC) as specified in the unit's Core Operating Limits Report as referenced in the technical specifications during the Cycle 7 reload analysis to ensure that the consequences are bounded by the analysis of record. Future cycle operation will be verified on a cycle specific basis during each cycle's reload safety analysis.

The licensee addressed the Standard Review Plan (SRP) Section 5.2.2. The licensee stated that the adequacy of the pressurizer and main steam safety valve sizing and setpoints for the proposed power uprate conditions was verified in the safety analyses for pressure peaking events. The safety valve sizes and setpoints are modeled in the CESEC code. Thus the acceptability of the current flow capacities of the valves at the proposed increased thermal power condition is verified by obtaining acceptable results for the pressure peaking events. The two limiting pressure peaking events are loss of condenser vacuum and feedwater line break. Both of these events result in peak pressures less than the acceptance criteria of the SRP for both the reactor coolant system and steam generators. Thus, the licensee concluded that the current safety valve sizing is acceptable at the increased rated thermal power condition.

The licensee stated that to evaluate the effect of the increased rated thermal power on the reactor coolant system low temperature overpressure protection, ABB-CE performed an analysis to determine the peak transient pressure that would result from a start of a reactor coolant pump under water solid conditions in the reactor coolant system, with a secondary to primary temperature differential of 100°F. Transient mitigation of the event was provided by one of two shutdown cooling suction relief valves to satisfy the single failure criterion of Branch Technical Position (BTP) RSB 5-2. The licensee concluded that, based on the analysis, the calculated peak pressure of 487 psia which is less than the existing design basis pressure of 488 psia and satisfies BTP RSB 5-2.

3.4.3 Decreased Reactor Coolant Flow Events (UFSAR 15.3)

3.4.3.1 Moderate Frequency Event

The licensee concluded that the total loss of forced reactor coolant flow is a margin-setting event which has sufficient thermal margin preserved in the core operating limit supervisory system and the other TS limiting conditions for operation such that in combination with the CPC pump speed trip function, the specified acceptable fuel design limits will not be violated during the loss of forced reactor coolant flow event.

3.4.3.2 Limiting Faults

The licensee stated that two events for Palo Verde fall into both the limiting fault frequency category and decreased reactor coolant flow event type: the RCP seized rotor and the RCP sheared shaft. In both events, a catastrophic malfunction in a single RCP results in a rapid coastdown in RCS flow.

The seized rotor, with more resistance to the RCS flow, has a slightly faster coastdown. When the RCP impeller and rotor assembly suddenly stop, CPCs perceive the reduction in RCP speed and generate a reactor trip.

The RCP sheared shaft allows a freewheeling coastdown of the impeller as the RCP motor continues to rotate. The RCS flow coastdown is slightly slower, but with the continued motion of the RCP motor, the CPCs do not generate a pump speed trip. Protection for this event is delayed until the steam generator differential-pressure low-flow reactor protection system (RPS) trip is generated.

The licensee examined both the RCP sheared shaft and seized rotor events for operation of PVNGS Unit 2 Cycle 7 at a proposed rated power of 3876 MWt. The licensee determined that the sheared shaft event produced slightly more fuel failure than the seized rotor. The fuel failure was calculated using the method of statistical convolution, which is consistent with the approved methodology for this event. The licensee indicated that less than 0.2 percent of the fuel pins are predicted to experience DNBR and fail for the reactor coolant shaft break for PVNGS Unit 2 Cycle 7. This fuel failure does not exceed the seized rotor/shaft break fuel failure of 4.5 percent reported in UFSAR Section 15.3.3. Thus, the licensee determined that the radiological consequences are less than the 240 Rem two hour site boundary thyroid dose reported in the UFSAR.

The licensee calculated the peak RCS pressures for the seized shaft and sheared rotor events to be less than 2100 psia. These events were not evaluated as pressure peaking events since they were not the limiting peak pressure events. The initial conditions for these events were chosen to maximize the DNBR in order to maximize the offsite dose consequences. The loss of offsite power for these events was assumed to occur at 3 seconds after the reactor trip in accordance with the current licensing basis, as discussed in the PVNGS UFSAR Section 15.6.3.2.2. The sheared shaft event had a calculated DNBR of 1.232 at 2 seconds and the seized rotor event had a calculated DNBR of 1.246 at 1.8 seconds. Because the calculated sheared shaft DNBR was lower than the seized rotor DNBR, the resulting sheared shaft fuel failure would be greater than the seized rotor fuel failure. The seized rotor fuel failure was not calculated by the licensee since it was bounded by the sheared shaft fuel failure. The loss of offsite power for the event occurs 3 seconds after the reactor trip in accordance with the current licensing basis and as discussed in the PVNGS UFSAR Section 15.6.3.2.2.

The licensee stated that it used the same methodology to examine the decreased reactor coolant flow rate limiting fault events as to support previous reloads of the Palo Verde units. The licensee indicated that the methodology is a two step process. The first step is to model the thermo-hydraulic conditions leading up to the DNBR SAFDL with the HERMITE code linked to CETOP to determine the time of minimum DNBR. In the second step the conditions from HERMITE at the time of minimum DNBR are examined in detail with thermal hydraulics of reactor core (TORC) to determine fuel failure.

The licensee stated that the set of initial conditions incorporated the maximized core-wide subcooling, preserves the minimum initial thermal margin in the hot channel required by the LCOs, and results in maximized fuel failure.

The licensee also stated that the fuel failure was calculated using the statistical convolution method, which is consistent with the approved methodology for this event. For PVNGS Unit 2 Cycle 7, the licensee determined that less than 0.2 percent of the fuel pins are predicted to experience DNBR and fail for the sheared shaft. The sheared RCP shaft event analysis was performed for power uprate operation for Unit 2 Cycle 7 and Unit 3 Cycle 6 midcycle implementation. The safety analysis for Unit 1 Cycle 7 will be reviewed at the power uprate conditions during the Cycle 7 reload analysis to ensure that the consequences are bounded by the analysis of record. Future cycle operation will be verified on a cycle specific basis during each cycle's reload analysis.

The licensee has concluded that this fuel failure rate does not exceed the seized rotor/sheared shaft fuel failure rate of 4.5 percent reported in UFSAR Section 15.3.3. Thus the radiological consequences are less than the 240 rem 2-hour site boundary thyroid dose reported in the UFSAR.

The staff questioned if the peak RCS and steam system pressures for the locked rotor event and the justification for the three-second delay in LOP (tripping of three undamaged pumps) had been addressed. The licensee stated that the locked rotor and sheared shaft events were analyzed to maximize the number of fuel pins experiencing DNB. These events were not reanalyzed for peak pressure since they were not the limiting peak pressure events. These events were analyzed previously for peak pressure to identify the limiting pressure peaking events, and are no longer analyzed for peak pressure. The peak pressure events are the loss of condenser vacuum, and feedwater line break. The licensee stated that since the results for these two, limiting, peak pressure events are within acceptance criteria, this demonstrates that the safety valve capacity and setpoints will be able to maintain reactor coolant system and steam generator pressures below their respective limits for the other, bounded, non-pressure peaking events.

The three-second delay was approved by the NRC on the CESSAR docket. In NUREG-0852, "Safety Evaluation Related to the Final Design of the Standard Nuclear Steam Supply Reference System CESSAR System 80," Supplement No. 1, dated March 1983, Section 15.3.7 (page 15-3), the NRC accepted the three-second time delay between the time of turbine trip and the time of loss of offsite power. The PVNGS Unit 1, 2, and 3 operating licenses states that the facility is described in both the PVNGS Final Safety Analysis Report and in the related CESSAR FSAR.

3.4.4 Reactivity Anomalies (UFSAR 15.4)

3.4.4.1 Moderate Frequency Events

3.4.4.1.1 High Power Bank CEA Withdrawal

The licensee stated that the CPC digital filters were verified to perform a conservative calculation of DNBR and local power density (LPD) for the spectrum of possible uncontrolled CEA withdrawal events. This verification has been performed for the proposed power uprate initial condition during the process of setting CPC constants for Unit 2 Cycle 7 and has been completed in Unit 3 for operation at the proposed increased RTP. This was documented in a letter from the licensee dated May 1, 1996. Unit 1 will be verified during the reload analysis process for the next cycle of operation when the proposed increased RTP will be implemented.

3.4.4.1.2 Full Length and Subgroup CEA Drops

The licensee stated that there is sufficient initial thermal margin preserved in the COLSS and the other LCOs to ensure that the SAFDLs are not violated during AOOs involving dropped CEAs. The COLSS constants calculated for the power uprate conditions for each unit and each cycle demonstrates sufficient thermal margin to prevent exceeding specified acceptable fuel design limits for full length and subgroup CEA drop events.

3.4.4.2 Limiting Faults

The licensee stated that the CEA ejection event from HFP initial conditions was evaluated under the proposed rerated power conditions for PVNGS Unit 2 Cycle 7. All of the criteria considered in the UFSAR (fuel performance [thermohydraulics and energy deposition], peak RCS pressure, and radiological consequences) were considered as part of this evaluation. The licensee stated that during the COLSS/CPC setpoint process, the CEA ejection from other power levels and configurations allowed by the power dependent insertion limit (PDIL) has been examined, and the constants installed for PVNGS Unit 2 Cycle 7 is adequate to ensure that the results reported are bounding.

The licensee also stated that the minimum DNBR of 0.7 occurs at 3.25 seconds. The number of pins predicted to experience DNB is less than the 9.8 percent currently reported. Therefore, the licensee concluded that the peak LHGR for the PVNGS Unit 2 Cycle 7 event is insufficient to melt the fuel. Additionally, the licensee determined that the maximum radially averaged fuel enthalpy is less than 140 calories/gram (cal/g) and the maximum centerline enthalpy is less than 250 cal/g.

The licensee stated that the sequence of events occurring after the time of most adverse fuel performance are essentially unchanged by the proposed rerated power condition. UFSAR Table 15.4.8-1 lists this sequence of events.

The licensee concluded that the excess power generation resulting from the ejection of the highest worth CEA for PVNGS Unit 2 Cycle 7 is bounded by existing calculations of peak RCS pressure during CEA ejection. By letter dated January 5, 1996, the licensee stated that the CEA ejection event analysis was performed for power uprate operation for Unit 2 Cycle 7 and Unit 3 Cycle 6 midcycle implementation. The safety analysis for Unit 1 Cycle 7 will be reviewed at the power uprate conditions during the Cycle 7 reload analysis to ensure that the consequences are bounded by the analysis of record. Future cycle operation will be verified on a cycle specific basis during each cycle's reload analysis. Thus the peak RCS pressure of the CEA ejection transient remains within the limits of 120 percent of the 2500 psia design pressure.

3.4.5 Increase in RCS Inventory (UFSAR 15.5)

The licensee stated that no reanalysis is necessary for this event. As stated in UFSAR 15.5.2.3.B, initial reactor power level and RCS temperature do not affect the consequences of the event. The effect of the reduced pressurizer safety valve setpoint of 2475 psia, as proposed for PVNGS Units 1 and 3, was evaluated for this event and found acceptable. This setpoint was previously changed in Unit 2 by Amendment 78, dated March 1, 1995.

3.4.6 Decrease in RCS Inventory (UFSAR 15.6)

3.4.6.1 Limiting Faults

3.4.6.1.1 Steam Generator Tube Rupture

The licensee stated that the radiological doses for this event are bounded by the results of the steam generator tube rupture with a concurrent loss of offsite power. Therefore, the licensee concluded that this event did not need to be reanalyzed for the power uprate.

3.4.6.1.2 Steam Generator Tube Rupture + LOP

The licensee stated that this event was evaluated to determine how the proposed 2-percent power increase and reducing the steam generator inventory affects the preexisting iodine spiking (PIS) and event-generated iodine spiking (GIS) radiological doses.

The licensee indicated that the 2-hour radiological doses for this event were increased by 2 percent to accommodate the 2 percent increase in decay heat. The licensee stated that this approach is conservative because the 2-hour radiological doses result from the steaming of the steam generators during the RCS cooldown and the decay heat removal. The licensee concluded that the new calculated 2-hour radiological doses remain less than the values of 40 and 17 rem for PIS and GIS, respectively, as reported in Table 15.6.3-10 of the UFSAR.

The licensee further stated that the total integrated decay heat generated by the rerated power core using the 1979 ANS decay heat curve with a 2σ uncertainty is less than the decay heat assumed in the previous analysis. Therefore, the licensee has concluded that the proposed power uprate will not require additional steaming beyond that assumed in the previous analysis to achieve shutdown cooling entry conditions and that the 8-hour radiological doses reported by the UFSAR remain bounding.

3.4.6.1.3 Steam Generator Tube Rupture + SF: Steam Generator Tube Rupture with a Loss of Offsite Power and Fully Stuck Open Atmospheric Dump Valve (ADV)

The licensee stated that the radiological doses for this event were recalculated to include the impact of the following two changes (the previous analysis was described in the licensee's May 16, 1994, submittal to NRC to support Amendments 75, 61, and 47, for Units 1, 2, and 3, respectively):

(1) the 2 percent core power increase to 3876 MWt; and

(2) a more conservative auxiliary feedwater actuation signal (AFAS) initiation analytical setpoint of 21 percent of wide-range (WR) span, instead of the 25 percent of WR span assumed in the previous analysis. (The TS Table 3.3-4 trip value is 25.8 percent of WR.)

The licensee also stated that a higher decay heat resulting from a proposed 2-percent rerated power in the core does not affect the 2-hour steam releases and radiological doses since they are driven by the stuck-open ADV in the affected SG. The stuck-open ADV in the affected steam generator removes much more heat than the core generates as decay heat. Therefore, the licensee concluded that the increased decay heat of the rerated power core does not affect the ADV releases during the period of SG tube uncovery, when most of the radiological releases occur.

The 8-hour decay heat for the proposed rerated power core using the 1979 ANS decay heat curve with a 2σ uncertainty is bounded by the decay heat used in the previous analysis. Therefore, the licensee concluded that the proposed rerated power core does not require additional steaming beyond that assumed in the previous analysis to achieve shutdown cooling entry conditions. The 8-hour radiological doses are not adversely impacted by the decay heat of the uprated power core.

The licensee also assumed lowering the analytical AFAS initiation setpoint from the currently assumed value of 25 percent of the wide range span to 21 percent. This increases the duration of the tube uncovery in the affected steam generator and therefore increases the radiological doses. The licensee stated that the new calculated radiological doses show that the 2-hour and 8-hour radiological doses for this event are less than the 10 CFR Part 100 thyroid limit of 300 rems.

The staff questioned if a steam generator tube rupture (SGTR) quantitative and qualitative analysis was done. The licensee stated that the SGTR was analyzed utilizing a comparison of the initial conditions in the analysis of record and the proposed rerated power conditions. The significant differences were the potential for increased decay heat due to increased thermal power and the increased time the tube bundle was uncovered due to a more conservative assumption in the potential error present in the auxiliary feedwater actuation setpoint (actuation at 21 percent versus old value of 25 percent wide range level). The increased decay heat would result in more steam being released due to the additional decay heat. The tube bundle uncovery results in a loss of partitioning and consequently an increased offsite dose. Using this comparison, the original calculated doses were increased by evaluating the potential magnitude of the differences.

Based on this comparison and maintaining conservative assumptions the following results were obtained by the licensee:

SGTR - The offsite doses are bounded by the analysis of record.

SGTR with Concurrent LOP - The 2-hour radiological doses were increased by 2-percent to account for the 2 percent increase in decay heat. The 8 hour doses of the analysis of record remain bounding because the integrated decay heat for the increased thermal power is bounded by the analysis of record.

SGTR with a LOP and Fully Stuck Open ADV - The 2-hour steam releases and radiological doses were not affected because the release from the ADV exceeds the decay heat generated in the core. The 8 hour doses were adjusted upward to account for the longer tube uncovery time due to the conservative assumption for auxiliary feedwater actuation setpoint.

3.4.7 Radioactive Release from a Subsystem or Component (UFSAR 15.7)

3.4.7.1 Waste-Gas- and Liquid-Containing Tank Failures

The licensee's analysis for tank failures in the UFSAR were performed using the maximum activities presented in Chapters 11 and 12 of the UFSAR. The conditions for the maximum activities are a 4100-MWt power level, a 1-year equilibrium cycle, and a 1 percent failed fuel. These conditions give an equilibrium dose equivalent iodine concentration of 4.6 microcuries/gram. TS 3.4.7.a limits the allowable dose equivalent iodine for continuous operation to 1.0 microcurie/gram. The licensee stated that PVNGS is limited by technical specifications to a fuel failure rate of approximately 0.25

percent. The licensee concluded that this establishes a factor of four safety margin for the consequences of these events and bounds the consequences of the proposed thermal power increase.

3.4.7.2 Fuel Handling Accident

The licensee stated that ABB-CE calculated the fuel element gas gap activity at the proposed increased RTP conditions and compared the result with the current UFSAR values. The calculation was performed using the ORIGEN-II code to quantify fission product inventories and using the methodology of ANSI/ANS-5.4-1982, "American National Standard for Calculating the Fractional Release of Volatile Fission Products from Oxide Fuel Elements," to calculate the fission product release fractions to the gas gap. The licensee stated that this methodology is consistent with that previously approved for the St. Lucie Plant, Unit No. 2 (Docket No. 50-389), in the safety evaluation report related to Amendment 21, dated May 29, 1987. The licensee stated that the pertinent assumptions for the calculation were a radial peaking factor of 1.70, a burnup of 70,000 megawatt-days per metric ton uranium (MWD/T), a 100-hour decay time, and a 5.0 percent uranium-235 enrichment. The licensee compared the results of the calculation to the current UFSAR values. All of the current UFSAR isotopic activities are higher than those calculated for the proposed increased RTP. The licensee has concluded that the current UFSAR consequences bound the proposed increased RTP consequences for a fuel handling accident.

3.4.8 ATWS Analyses

The licensee stated that there were two parameters associated with increasing the RTP from 3800 MWt to 3876 MWt that are potentially affected. These are the equipment setpoints and the moderator temperature coefficient used in the anticipated transients without scram (ATWS) analyses. Both of these parameters were considered and determined not to be impacted by operation at the proposed increased RTP.

Section 50.62 of Title 10 of the Code of Federal Regulations requires that pressurized water reactors supplied by ABB-CE have systems diverse from the reactor trip system to scram the reactor, trip the turbine, and initiate auxiliary feedwater under conditions indicative of an ATWS. To comply with these requirements, the supplemental protection system (SPS) will trip the reactor and cause the turbine to trip, and the diverse auxiliary feedwater actuation system (DAFAS) will initiate auxiliary feedwater. The SPS must provide a trip promptly in the event of an ATWS, but not interfere with the action of the RPS. Therefore, the SPS setpoint, pressurizer pressure of 2409 psia, was conservatively selected to be greater than the RPS trip setpoint and less than the pressurizer safety valves set pressure. Similarly, the DAFAS must initiate auxiliary feedwater promptly in the event of an ATWS, but not interfere with the action of the auxiliary feedwater actuation system. On this basis, the DAFAS setpoint of 20 percent wide range steam generator level was conservatively selected. Therefore, the licensee concluded that increasing the RTP from 3800 MWt to 3876 MWt does not require a change to the SPS and DAFAS setpoints and does not diminish the effectiveness of these setpoints.

The licensee further stated that ATWS analyses were performed from nominal initial conditions at a negative MTC that was more positive than that existing during 95 percent of the cycle. The licensee concluded that increasing the RTP by 2 percent does not change the allowable MTC, and hence does not impact the ATWS analyses. With respect to the fuel performance in general, UFSAR Section 3.4.1 states that the DBEs were evaluated with respect to four criteria, one of which was fuel performance (specified acceptable fuel design limits). The licensee stated that all events were re-evaluated to assure that they meet their respective criteria. Also, the licensee stated that there are no plant modifications or changes in fuel design required for the proposed RTP increase.

3.4.9 Miscellaneous Considerations

3.4.9.1 CEA Issues

The staff questioned what effects the reduction in temperature (552°F to 550°F) would have on a control element assembly drop time and also the uprate effect on the recent issue of the failure of CEAs to fully insert when positioned over high burnup fuel assemblies. The licensee stated that the safety analyses assume a CEA drop time of 4.0 seconds. Actual drop times are approximately 2.5 seconds, based on drop tests performed at a nominal T_{cold} of 565°F. The 565°F T_{cold} testing temperature is an isothermal RCS temperature to replicate the nominal average core water temperature during power operation. The drop times to date for all PVNGS units have been typically 2.5 to 3 seconds. At 565°F, 2250 psia, RCS water density is 45.863 lbm/ft^3. At 550°F, 2250 psia, the RCS water density is 46.864 lbm/ft^3. This small difference in density has a negligible effect on CEA drop time. Additionally, the average density of the fluid in the core is less than this value as power is increased. The licensee determined that there is sufficient margin in actual vs. assumed drop times (3 vs. 4 seconds) to bound RCS density effects for the small change in operating temperature that would result from the two degrees lower allowable T_{cold} (552°F to 550°F). In addition, testing at lower temperatures, as would be allowed by the change to TS 3.1.3.4, would provide even more conservative CEA drop times.

The licensee indicated that the recent operating experience at other, non-CE System 80 plants regarding the failure of CEAs to insert when positioned over high burnup fuel (NRC Bulletin 96-01) is not applicable to the PVNGS fuel design. In Bulletin 96-01, the NRC identified recent operating experiences at other, non-CE System 80 plants regarding the failure of control rods to insert when positioned over high burnup fuel. The licensee stated that the PVNGS burnup limit is not being changed with this increase in RTP, and that the small increase in rated thermal power associated with this proposed amendment would not have a detrimental effect on the fuel assembly performance. Further, the licensee stated that the fuel assembly design which is associated with the binding of the CEAs in NRC Bulletin 96-01 is not used at PVNGS. CEA drop times are trended and there have been no discernible changes in drop times over the previous cycles.

3.4.9.2 Fuel Performance (e.g. Clad Oxidation, Temperatures, etc.)

The licensee stated that fuel temperatures, fuel rod internal pressure, and the power to fuel centerline melting were evaluated in fuel performance analyses. The core average linear heat rate and maximum radial peaking factor associated with operation at 3876 MWt (plus a 2 percent uncertainty) were used in these analyses. In general, the resulting fuel temperatures and rod internal pressures are expected to be slightly higher for operation at 3876 MWt compared to operation at 3800 MWt. However, the higher fuel temperatures and pressures are accounted for in the accident analyses, including LOCA and non-LOCA transients. Furthermore, the licensee has determined that the fuel performance analyses verified that no fuel performance limits (e.g., the critical rod internal pressure for no clad lift-off) are violated.

The licensee also stated that the impact on cladding oxidation of the proposed increase in RTP is not significant. The licensee determined that operation at the reduced RCS temperatures associated with the proposed rerate and previous license amendments provides margin that is sufficient to bound the small increase in RTP.

3.4.9.3 Asymmetric Steam Generators

The licensee stated that the asymmetric steam generator transient (ASGT) is protected against by initial thermal margin in core operating limit supervisory system, the TS LCOs, and the core protection calculator ASGT trip function. This combination is selected to ensure that the SAFDLs are not violated for this anticipated operational occurrence.

The licensee also stated that the ASGT event which causes the most rapid degradation in thermal margin is the closure of a main steam isolation valve. The adequacy of the ASGT analysis at the proposed increased RTP conditions has been verified during the CPC/COLSS setpoint process for Unit 2 Cycle 7 and the analysis to support midcycle implementation in Unit 3. By letter dated May 1, 1996, the licensee stated that the Unit 1 constants will be verified during the normal reload analysis process for its next refueling cycle.

3.4.10 Conclusions

The licensee has assessed each of the non-LOCA transient event categories and has concluded that the applicable SRP acceptance criteria (e.g., peak system pressure, DNB, radiological consequences, peak cladding temperature, system performance requirements, etc.) remain satisfied for the proposed power uprate conditions. The staff has reviewed the licensee's submittals and, based on the information provided, finds that the licensee has adequately addressed non-LOCA transient considerations for the proposed RTP increase.

3.5 Source Term

The licensee stated that the original source term for the PVNGS LOCA calculations is given in UFSAR Table 6.3.3.6-1. This source term was based on a power level of 4200 MWt and operation for 2 years. A new source term was calculated by ABB-CE using the ORIGEN-II code (for LOCA transients) for 3876 MWt (plus a 2 percent uncertainty), 5 weight percent enrichment U-235, and an 18-month equilibrium cycle. The licensee made a comparison between the new and old source terms. Except for Kr-85, Xe-131M, and Xe-135, the new source term values are below the current source term curie content. All the new source term iodine isotopes inventories are bounded by the current source term, and thus the licensee concluded that the new source terms are bounded by the current thyroid dose calculations.

The assumptions used for the new source terms which were computed by ABB-CE using the ORIGEN-II code for non-LOCA transients, were 3876 MWt (plus a 2 percent uncertainty), 5 weight percent enrichment U-235, and burnups of 20, 30, and 40 gigawatt-days per metric ton of uranium (GWD/T). An evaluation of the new source term (non-LOCA) versus the previous non-LOCA source term was performed using the highest curie content of each isotope from the three fuel burnups. The licensee performed its evaluation only on events where fuel failure is predicted since the technical specification limits on RCS and steam generator activity are unchanged.

The licensee stated that it looked at excess load with loss of offsite power (LOAC), pre-trip steamline break, seized rotor/sheared shaft, and CEA ejection. The pre-trip steamline break as described previously is analyzed such that SAFDL violations do not occur; therefore, the licensee concluded that the source term is not a consideration. The licensee also concluded that the excess load with LOAC and seized rotor/sheared shaft events were found to have enough margin in the source term used in the current radiological analysis to bound the new source term.

The licensee stated that several changes were required to update the radiological consequences assessment of the CEA ejection to be consistent with the current methodology. The licensee indicated that the UFSAR CEA ejection event was found to have used a bounding source term, but not a bounding radial peaking factor. Additionally, the UFSAR dose was based upon a 9.8-percent failure rate in the first cycle core, which contained many shim rods without uranium dioxide (UO_2). The licensee stated that current practice is to assume that all fuel rod locations are UO_2 bearing, which is consistent with the expanded use of integral burnable poisons. Therefore, the radiological consequences of the CEA ejection event required review. The licensee concluded that, as a result of the review of the radiological consequences of the CEA ejection event, the previously used radial peaking factor of 1.46 is less than the currently used value of 1.70. Therefore, the new peaking factor increases the source term by approximately 17 percent. The licensee stated that the differences in source term from the original analysis and the new source term value amount to approximately a 10 percent reduction in iodine isotopes. The licensee stated that applying the new source term and the new radial peaking factor for this event increases the reported consequence by approximately 7 percent. In addition, with the increased number of potential fuel pin locations, the doses were also adjusted upwards to reflect the failure of 9.8 percent of every fuel rod location. Overall, these effects combined to give a 15 percent increase in the site boundary thyroid doses.

The licenseee stated that the new values continue to be within the 10 CFR Part 100 limits of 300 rem. In addition, the licensee stated that Supplement 1 to the CESSAR SSER (NUREG-0852) evaluated the CEA ejection and determined that 10 CFR 100 limits would be appropriate for this event, considering the conservatism present in the calculation.

In addition, the licensee stated that since the whole body doses for this event are extremely small compared to the regulatory limits, detailed calculations were not performed. However, to conservatively quantify this difference, the current UFSAR doses were doubled to give acceptable results. The licensee's results show that the beta and whole body skin doses are still small compared to the 10 CFR Part 100 limits.

The licensee also indicated that the CEA ejection transient has slightly higher doses than those previously reported because of a higher allowable radial peaking factor. The licensee concluded that this is acceptable since it is still within 10 CFR Part 100 limits.

The licensee provided an evaluation of the effect of the proposed rerate on accident radiological consequences. The original licensing basis accident analysis of source terms for PVNGS were conservatively assumed based on a core power level of 4200 MWt. The licensee performed a recalculation, using methodology and assumptions which are consistent with the original licensing basis. The doses were calculated for the exclusion area, low-population zone, and control room. Based on these calculations, the licensee has concluded that the doses differed slightly from those presented in the original licensing basis, but in all cases remain below applicable regulatory limits.

In its submittals, the licensee concluded that the radiological consequences of design basis accidents (DBAs) are acceptable at the increased core power level. The basis for this conclusion was that radiological consequences of DBAs affected by the power uprate are bounded by the current licensing basis. The staff reviewed the licensee's analyses and compared the potential radiological consequences to the current licensing basis and the acceptance criteria presented in 10 CFR Part 100 and General Design Criterion 19 of Appendix A to 10 CFR Part 50 (GDC 19).

The majority of the previous DBA analyses assumed a core power level of 4100 MWt or a fuel failure rate of 4.5 percent, which are greater than the proposed core power level of 3876 MWt and a predicted fuel failure rate of less than 0.2 percent. Thus, it was not necessary to recalculate radiological consequences for the majority of the design basis accidents described in Chapter 15 of NUREG-0800 because previous analyses were performed at a greater core power level and fuel failure rate. For the DBAs that required reassessment for the power uprate, a large break loss-of-coolant accident (LOCA) and a steam generator tube rupture accident, the staff independently calculated the postulated radiological doses for individuals located at the exclusion area boundary (EAB), low-population zone (LPZ), and control room.

For the LOCA dose calculation, the staff used assumptions contained in Supplement No. 5 of NUREG-0857 and the staff's Safety Evaluation (SE) associated with Amendment No. 63 to Facility Operating License No. NPF-41, Amendment No. 50 to Facility Operating License No. NPF-51, and Amendment No. 37 to Facility Operating License No. NPF-74, dated September 8, 1992. The staff also incorporated new information provided by the licensee in the May 5, 1996, submittal on the leak rate of the emergency core cooling system and atmospheric dispersion from release points to the control room intakes. The assumptions used to calculate the LOCA doses are listed in Table 1 and the calculated doses are listed in Table 2 of Attachment 1. The staff concluded that the radiological consequences of a large break loss-of-coolant accident at a reactor core power of 3954 MWt are within the acceptance criteria presented in SRP 15.6.5, Appendices A and B of NUREG-0800, and SRP 6.4.

For the SGTR dose calculation, the staff used information contained in the PVNGS UFSAR and new information provided by the licensee in the January 5, 1996, submittal. Revised atmospheric dispersion estimates from releases points to the control room intakes were also used in the staff's analysis. In accordance with SRP 15.6.3, two assessments were performed for the most limiting scenario, which is a SGTR with a loss of offsite power and fully stuck open atmospheric dump valve. The assessments included an accident-initiated iodine spike and a pre-existing iodine spike. For the pre-accident spike assessment, the staff's calculations indicate that thyroid doses are within the acceptance criteria presented in SRP Sections 6.4 and 15.6.3. For the accident-initiated spike assessment, the staff's calculations indicate that thyroid doses to the control room operators are within the acceptance criteria presented in SRP 6.4 and that thyroid doses at the EAB and LPZ are less than the guideline values of 10 CFR Part 100, which is the current licensing basis for PVNGS (see references 1 and 2 of Attachment 1). The results of these calculations and parameters which were utilized in the staff's assessment (see Tables 3 and 4 of Attachment 1, respectively). The staff concludes that the radiological consequences of a SGTR accident with a loss of offsite power and fully stuck open atmospheric dump valve at a reactor core power of 3954 MWt are within the current licensing basis.

The staff has reviewed the radiological consequences for the proposed change for each of the three PVNGS units to increase the authorized 100 percent reactor core power to 3876 MWt (a 2 percent uncertainty), and the radiological consequences are within the current licensing basis.

The staff concluded that for the design basis accidents which are impacted by the 2 percent power uprate, neither the offsite doses nor the control room operator doses, would exceed the licensee's current licensing basis. Therefore, the staff finds the proposed power uprate acceptable from a radiological consequences standpoint.

3.6 Systems and Programmatic Reviews

3.6.1 Nuclear Steam Supply Control System

The licensee's evaluation used the proposed rerate power level of 3876 MWt (plus a 2 percent uncertainty) and included a reduction in feedwater temperature to 425°F at full power and operation with the reduced RCS hot-leg temperature of 611°F. Steam generator modifications were also assumed (removal of the steam separator orifices, the addition of flow passages to the tube bundle shroud, and replacement of the downcomer feed ring to reroute the downcomer feedwater flow to the hot side of the steam generator).

The licensee stated that the current nuclear steam supply system (NSSS) control system setpoint changes, determined under the feedwater temperature reduction project, were used, except for the reactor regulating system (RRS) setpoints, which were revised to incorporate changes recommended by a recent evaluation of the RRS. The RRS changes are scheduled for implementation in the first quarter of 1996 and thus will be in place before implementation of proposed power uprate.

The licensee evaluated the current feedwater control system (FWCS) setpoints for the steam generator modification project using computer simulation of key control system design basis maneuvering transients. The licensee concluded that the current setpoints provide good level control stability with no adverse impact on transient response capabilities at the proposed uprated conditions.

The licensee also stated that the NSSS control system design basis maneuvering transients (which were most challenging from the standpoint of margin to plant trip or steam generator level control stability) were selected for simulation assuming proposed power uprate conditions. The licensee concluded that, based on the simulation, the steady-state and transient performance of the NSSS control systems would be adequate using the latest setpoints at the proposed rerate power level of 3876 MWt.

The staff has reviewed the licensee's submittals and has concluded that the licensee has adequately addressed the nuclear steam supply control system for operation at the proposed rerate conditions.

3.6.2 Nuclear Steam Supply System Mechanical Evaluation

The licensee evaluated design stresses and fatigue usage factors for the plant design operating temperature and transients at 3876 MWt (plus a 2 percent uncertainty) for the reactor vessel and internal components, reactor coolant piping and fittings, pressurizer, steam generator, and reactor coolant pump. The evaluation concluded that the transients at the proposed uprated power operating conditions are bounded by the original design transients, and the design analysis of record is not significantly affected by the change in operating temperature at the proposed uprated power. The licensee concluded that structural integrity of these major components of the RCS at Palo Verde

Units 1, 2 and 3 would not be affected at proposed increased RTP operating conditions at T_{hot} of 611°F and T_{cold} of 550°F.

The licensee also evaluated the LOCA loadings for the proposed power uprate by revising the existing LOCA calculation which was performed in 1994 in support of a 10°F T_{hot}/T_{cold} temperature reduction effort. The licensee stated that the calculation resulted in (1) LOCA blowdown loads, (2) mass and energy releases, and (3) steam generator subcompartment pressurization analyses for the limiting postulated break in the tributary lines in the hot and cold legs. These analyses were performed to determine the effect of decreasing the reactor vessel inlet temperature from 565°F to 555°F.

The licensee stated that the new operating setpoint for the reactor vessel coolant inlet temperature associated with the proposed 2 percent RTP increase would be 554°F, which is 1°F less than the current operating point. ABB-CE has previously performed a LOCA blowdown load structural analysis for PVNGS to justify a previous 10°F reduction in T_{cold}. The licensee indicated that the loads resulting from the 10°F reduction were insignificant when compared to the loads considered in the original structural response analyses. Based on the above, the licensee concluded that the effect of an additional 1°F decrease in the reactor vessel inlet temperature (from 555°F to 554°F) would still be bounded by the loads considered in the original LOCA blowdown loads structural analysis.

Based on the above, the staff concluded that the proposed uprated power conditions will not have any adverse effects on the structural integrity of the RCS components such as the reactor vessel internals, piping and fittings, pressurizer, steam generator and reactor coolant pump. The staff reviewed the licensee's submittals and concluded that these components will satisfy their design functions under the proposed uprate conditions.

3.6.3 Steam Generator Mechanical Assessment

The licensee evaluated the effects of the increased RTP, reduced T_{hot}, and reduced feedwater temperature on steam generator internals during normal and accident conditions for all three Palo Verde units. The licensee stated that the evaluation consisted of reviewing the existing design analyses of the current licensing basis with regards to hydraulic loads, thermal and fluid transients, blowdown forces and flow-induced vibration.

Also, the licensee stated that conditions on the secondary side of the steam generator at the rerated power operation (including the steam generator modifications) were analyzed for the steam generator internal components. The analysis showed that operation at the proposed rerate power slightly decreases secondary fluid velocity (as a result of the lower recirculation ratio) and slightly increases fluid density (as a result of lower cold-leg temperature). The licensee concluded that these two conditions result in a lower dynamic pressure (ρV^2) and hence, less energy transmitted from the secondary fluid to the steam generator internal components and lower hydraulic loading conditions on the components.

The licensee also evaluated the transients specified in the general specification for System 80 steam generator and concluded that these transients are not significantly altered for the proposed power uprate condition. Considering the seismic loads which are the primary contributor to the stresses in the internal components including the tubes, the licensee further concluded that the changes in the transients will not adversely affect the tubes and other steam generator components at the uprated power condition. Therefore, the licensee determined that implementation of the proposed power uprate with reduced feedwater temperature will not adversely affect the steam generator internal components including the tubes.

In addition, the licensee evaluated the effects of the reduction in feedwater temperature for the fatigue usage factor at the critical location of the economizer feedwater box because of a slight increase in the secondary shell-to-feedwater box temperature differential. The licensee concluded that these effects are negligible in comparison to the stresses associated with the design basis assumption of 40°F feedwater at 15 percent power (500 cycles each of plant loading and unloading). Hence, the fatigue usage factor will remain below the ASME Code allowable value of 1.0 for the proposed power uprate.

In evaluating the blowdown hydraulic loads from a main steam line break, the licensee stated that the operating pressure has decreased by approximately 100 psi as a result of the proposed power uprate and the 10°F decrease in hot-leg temperature. The licensee concluded that, based on the flow through the postulated break is saturated steam, the loads are dependent on operating pressure and therefore, will be lower for the uprated power condition. The licensee evaluated the loads associated with the FWLB and concluded that the FWLB loads will decrease slightly for the proposed power uprate because the decreased operating pressure will adequately off-set the load increase resulting from the reduction in feedwater temperature.

The licensee stated that ABB-CE performed extensive analysis of flow-induced vibration (FIV) of the tube rows nearest the shroud holes installed as part of the steam generator modifications. The calculated flow stability ratio was 0.765 for the proposed power uprate in comparison to the previously calculated stability ratio of 0.79 for the design power level. Based on this, the licensee concluded that the proposed power uprate will not increase the potential for flow induced vibration.

The licensee stated that the minimum acceptable steam generator tube wall thickness for the original design basis conditions was 0.015 inches (36 percent of the wall thickness) using the criteria of Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes." With the 10 degree T-hot reduction, the licensee determined that the minimum acceptable wall thickness increased to 0.016 inches (38.5 percent of the normal wall thickness). Under the proposed rerate condition, however, the licensee concluded that the change in differential pressure across the steam generator tubes was negligible (approximately 2 pounds per square inch) and therefore no changes to the technical specifications plugging limits were required. The technical specification plugging limit is based on an imperfection depth of 40 percent (minimum undegraded wall thickness of 60 percent).

The licensee stated that they do not expect the proposed power uprate to negatively impact steam generator damage rates and that its program for managing steam generator tube degradation is capable of assessing any possible changes resulting from the proposed uprate.

The staff has reviewed the licensee's submittals and has concluded that the information presented on the steam generator mechanical assessment, and steam generator internals are acceptable for plant operation during normal and accident conditions at the proposed uprate conditions.

3.6.4 Probabilistic Risk Assessment

The licensee stated that the PVNGS thermal-hydraulic and severe-accident-progression models were revisited to support this proposed 2 percent increase in RTP. Five of the 25 source term categories were reexecuted using MAAP3B Revision 17.02, with changes to the MAAP input deck reflecting applicable changes associated with the proposed RTP increase. The STCs selected for sensitivity runs were determined to be representative because of their potential for large early releases. The licensee indicated that, based on the results, the timing of key events and source term releases do not impact the baseline risk for a large early-release potential due to power uprate modifications.

The licensee concluded that, based on the above, the only effect of a 2 percent increase in RTP on shutdown risk is to slightly increase decay heat, slightly altering the time-to-boil and core uncovery calculations. Operators will have approximately 2 percent less time to act. The event sequences will be unaffected. The two percent reduction in time for operator action is not considered significant to the successful completion of the action and therefore does not significantly affect the risk associated with shutdown.

The staff has reviewed the licensee's submittals and finds that probabilistic risk assessment (PRA) considerations do not pose a problem for the proposed 2 percent RTP increase.

3.6.5 Impact of Increased RTP on Operations, Procedures, and Simulator Training

The licensee indicated that it will change two procedures to support the proposed increased reactor thermal power. First, the power operations procedure will be changed to normally operate at full power with the high-pressure feedwater heater bypass valve open. Currently, this valve is normally closed. The effect of operating with it open will be a reduction in feedwater temperature, as well as a slight decrease in electrical output. Reducing feedwater temperature will help prolong the expected life of steam generator tubes. The licensee indicated that an option will be provided in the procedure to operate with the high-pressure feedwater heater bypass closed to maximize electrical output. This change in feedwater heater operation is not required for the proposed power uprate, but is being coordinated as part of the overall strategy to maximize steam generator tube life. Second, the licensee stated that surveillance test procedures will be modified to reflect the change in the cold-leg temperature TS limits. Licensed operators have received classroom training on the power uprate and associated procedure changes.

The licensee stated that the power uprate modifications will be implemented in the simulators within a year of the uprate being implemented. The simulator modifications will consist of changes to COLSS addressable constants, the primary safety valve setpoint, and nuclear instrument indication. The licensee concluded that operators will not be adversely affected by training on a simulator that, for a time, does not reflect the proposed power uprate at which the units operate. The licensee also stated that there are currently minor differences between the operating characteristics of the units and the changes associated with the proposed uprate. These changes are sufficiently small (i.e., no more than two or three percent changes in most operating parameters, except for reduced feedwater temperature) that they will not affect the applicability of the training scenarios for operators from units that have implemented the proposed power uprate. The staff questioned when operations crew training will be completed. The licensee stated that operations crews were briefed on proposed increased rated thermal changes during the last requalification training cycle.

Based on the licensee's response, the staff has concluded that training requirements are acceptable for operation at the proposed rerate conditions.

3.6.6 Containment Heating, Ventilation and Air Conditioning (HVAC)

The licensee performed a reanalysis of heat loads from insulated piping and components in the containment building was originally analyzed for the bulk containment volume. The licensee stated that the analysis used a surface emissivity of 80 BTU/hr/ft^2. The analysis does not directly utilize the system operating temperatures, but instead is based on the piping and components being insulated to a OSHA-mandated insulation surface temperature of 140°F and on the actual surface emissivity of the insulation being less than or equal to that analyzed in the heat load calculation.

The licensee stated that the reflective metallic insulation installed on the reactor coolant system and branch line piping in the Palo Verde containment was specified with surface emissivity of 55 BTU/hr/ft^2. This lower surface emissivity is conservative with respect to that used in the heat load calculation and results in a smaller heat load to the containment than used in the actual analysis. Additionally, the reflective metallic insulation specification establishes that the maximum operating temperatures of the insulated lines were 620°F for RCS hot-leg side piping, and 565°F for RCS cold-leg side piping. These temperatures bound the post-T_{hot}-reduction hot-leg temperature of 611°F and the post-power-upgrade T_{cold} temperature of 554°F.

The licensee stated that the impact of T_{hot} reduction to 611°F and T_{cold} reduction to 564°F will be similar for the non-safety-related reactor cavity cooling subsystem, and for the control element drive mechanism (CEDM) cooling units.

The licensee concluded that the post-power-upgrade operating temperatures of 611°F for T_{hot} and 554°F for T_{cold} result in a lower total heat load to the containment building, and the existing containment cooling system components have an increased degree of operating margin.

The staff has reviewed the licensee's submittals and has concluded that the proposed rerate conditions were found to have negligible impact on the requirements for or performance of HVAC systems. The staff finds the licensee's conclusions acceptable for operation at the proposed uprate conditions.

3.6.7 Station Blackout (SBO)

The licensee stated that PVNGS is designated as a 4 hour SBO coping plant; however, since the installation of an alternate AC power source, i.e., redundant dedicated gas turbine generators (GTGs), coping is only required for a 1-hour complete loss of AC power. Within that 1 hour all loads required to maintain the plant in a hot-standby condition are energized from the output of a GTG. An existing study on how PVNGS copes for the 1 hour while the GTGs are started and the required loads are energized was reviewed. The licensee has concluded that this study is not affected by the proposed 2 percent RTP increase.

The licensee stated that during an SBO, decay heat is removed by the steam-turbine-driven auxiliary feedwater pump and the pneumatically operated atmospheric steam dump valves. These loads require only Train A 125 Vdc power for operation. The Train A 125 Vdc system is energized from a GTG, thereby ensuring that the DC system and loads powered from it are available for the duration of the SBO. The licensee has concluded that since the steam turbine and atmospheric dump valves do not require increased electrical demand as a function of decay heat, their operation is not affected by the proposed 2-percent RTP increase.

The licensee also stated that the required condensate inventory is 85,000 gallons for a 4-hour SBO. The minimum available inventory is 300,000 gallons as required by TS 3/4.7.1.3. Thus, there is ample condensate inventory even with a slightly increased decay heat.

The licensee further stated that the reactor coolant inventory after a four-hour SBO event was analyzed to be sufficient to keep the core covered and cooled by reflux boiling in the steam generators. The licensee concluded that this study remain valid for the proposed increased RTP, although the coping period might be slightly reduced. However, since coping is only required for one-hour, rather than four hours, there is sufficient margin to accommodate the proposed increased RTP. Following the SBO coping period, reactor coolant inventory is maintained by operation of the train A charging pump as energized from the GTG output. The flow capacity of the charging pump is sufficient to provide makeup for all anticipated reactor coolant system leakages.

The staff has reviewed the licensee's submittals and has concluded that the proposed increased RTP will not affect PVNGS's ability to cope for the 1-hour period required before restoration of power from the GTGs.

3.6.8 Post-LOCA Hydrogen Generation

The licensee has reviewed the post-LOCA hydrogen generation analysis to determine if the proposed 2 percent RTP increase has a significant effect on post-LOCA hydrogen generation. The revised containment post-LOCA temperature profile has also been included in this analysis. The higher decay heat is predicted to increase the hydrogen generated by radiolytic decomposition of water by approximately 1.9 percent. The licensee determined that the proposed increase in reactor power level and decay heat also affects the core wide oxidation rate used to predict the quantity of hydrogen released as a result of the zirconium-water reaction. Using the calculated core-wide oxidation rate of 0.86 percent and placing the hydrogen recombiners into service at 100 hours, the peak predicted hydrogen concentration is less than 3.99 percent by volume.

The staff has reviewed the licensee's submittals and has concluded that the current hydrogen generation analysis remains bounding. The hydrogen control systems and the related hydrogen generation analysis are not affected by the proposed rerate conditions and are, therefore, acceptable.

3.6.9 Natural Circulation Cooldown Analysis

The licensee provided the results of a natural circulation cooldown analysis performed as part of its proposed power uprate project. The purpose was to demonstrate that the Palo Verde plants could be cooled to shutdown cooling entry conditions after a loss of offsite power from full power uprate operating conditions (102 percent of RTP), using the latest plant specific operating procedures and, in accordance with the requirements of BTP RSB 5-1, using either:

(1) one charging pump and auxiliary spray for RCS inventory and pressure control, or

(2) one HPSI pump and the safety grade reactor coolant gas vent system (RCGVS) for RCS inventory and pressure control.

The licensee stated that the existing Palo Verde System 80 natural circulation cooldown analysis credits two charging pumps and auxiliary spray for RCS inventory control and depressurization. The safety grade reactor vessel upper head (RVUH) gas vents, along with charging, were credited for control of RVUH steam voiding. Two new simulations of a cooldown to SDC entry conditions were performed under natural circulation conditions consistent with the criteria of BTP RSB 5-1 and PVNGS operating procedures.

The licensee stated that the first simulation was performed using a single charging pump and auxiliary spray for RCS inventory and pressure control. The licensee's second simulation was performed using one HPSI pump and the RCGVS pressurizer vent for RCS inventory and pressure control. The licensee assumed one, rather than two, charging pumps for the first simulation to provide consistency with the PVNGS licensing basis test report of record. Both scenarios utilized the RCGVS RVUH vent for upper head void control.

Each unit at PVNGS has three charging pumps. One pump is powered by Train A, the second pump is powered by Train B, and the third, "swing" pump can be aligned to either Train A or Train B. The licensee's existing analysis assumed that one charging pump and one auxiliary spray were initially available for RCS inventory and pressure control and that two charging pumps and auxiliary spray were available after 30 minutes. The licensee's assumption was based on the estimated time required to align the third, swing charging pump from one train of power to the other if it is initially powered by the train whose diesel generator is assumed to fail to start.

The licensee stated that the first simulation assumed that only one charging pump and auxiliary spray are available for RCS inventory and pressure control and does not rely on the need for operator action outside the control room to align the third, swing charging pump from the failed train of power to the operable train of power. In addition, this scenario demonstrated a "defense in depth" since the third, swing charging pump can be considered as a backup in the unlikely event that there were a loss of offsite power followed by a failure of one emergency diesel generator to start and a failure of the charging pump powered by the operable emergency diesel generator.

The licensee stated that the results of the simulation demonstrated that a single charging pump and auxiliary spray were adequate for RCS inventory control and depressurization during a cooldown scenario. During the simulation the operator actions required to cooldown and depressurize the RCS to well within SDC entry conditions were completed in 10.7 hours. At this time, the total safety grade condensate usage was 211,900 gallons. The licensee concluded that given an additional 1.3 hour allowance for stabilization and shutdown cooling entry, the resulting total of 12.0 hours is well within the 13.3 hour capacity of the nitrogen backup supply for the ADVs. Including the 1.3 hour allowance for plant stabilization, only 227,200 gallons of safety grade condensate was used, well within the technical specification minimum available supply of 300,000 gallons.

The licensee stated that the second simulation utilized one HPSI pump and the RCGVS pressurizer gas vent for RCS inventory and pressure control. This is a diverse and redundant means of the charging and auxiliary spray for RCS inventory and pressure control. This provides the PVNGS design with "defense in depth" for RCS inventory and pressure control during a natural circulation cooldown scenario.

The licensee stated that results of the simulation demonstrate that the use of HPSI flow and the safety grade RCGVS pressurizer gas vent provide a satisfactory redundant and diverse means (to charging and auxiliary spray) for RCS inventory control and depressurization. When the use of one HPSI pump and the pressurizer gas vent were simulated, operator actions to cooldown and depressurize the RCS to within SDC entry conditions were completed in 11.0

hours. At this time, the total safety grade condensate usage was 216,400 gallons.

In addition, adding a one-hour allowance for stabilization and shutdown cooling entry, the resulting total of 12.0 hours is within the 13.3 hour limitation based on the 13.3 hour capacity of the nitrogen backup supply for the ADVs. Even with the one-hour allowance for plant stabilization, only 227,100 gallons of safety grade condensate was used, well within the technical specification minimum available supply of 300,000 gallons.

The criterion of BTP RSB 5-1 that is applicable to the Palo Verde licensing basis requires demonstrated that the plant can be brought to cold shutdown conditions (200°F) within a reasonable time of shutdown, assuming the availability of only onsite or offsite power and assuming the most limiting single failure. The residual heat removal function is accomplished in two phases: the initial cooldown phase and the shutdown cooling phase. The residual heat removal operation phase, bringing the plant from SDC entry conditions to cold shutdown, was analyzed by the licensee.

The licensee stated that results of the analyses demonstrated that with the balance of plant interface requirements met, the unit could be brought to cold shutdown within a reasonable time (i.e., 36 hours), consistent with the criteria specified in BTP RSB 5-1. The licensee stated that the analyses show that the system capabilities comply with the guidance provided in BTP RSB 5-1 and 10 CFR Part 50.

The staff has reviewed the licensee's submittals and has concluded that the impact of the proposed rerate conditions is minimal and that the performance of the residual heat removal function for PVNGS is consistent with BTB RSB 5-1 and 10 CFR Part 50, and is therefore, acceptable for operation at the proposed uprate conditions.

3.6.10 Decay Heat Removal and Ultimate Heat Sink Performance

The licensee stated that the essential cooling water (EW) and spray pond (SP) system thermal performance analyses have been revised to account for the proposed 2 percent increase in the RTP. The thermal performance and capacity of the ultimate heat sink (UHS), which at Palo Verde consists of the spray ponds, is modeled as an integral part of the EW and SP system thermal performance analyses. At Palo Verde the spray pound is the ultimate heat sink. The licensee stated that the decay heat used in the analyses was in accordance with BTP 9-2. Also, the thermal performance analyses for the LOCA cases were performed using the COPATTA code. Although the peak EW and SP temperatures were predicted to increase by a few degrees as a result of the decay heat, the licensee confirmed that the heat removal capabilities of the EW and SP systems were adequate to remove heat from the shutdown cooling operational mode of the safety injection system, from the essential chiller, from the spent fuel pool cooling system, and from the emergency diesel generator.

The licensee's submittal also indicated that the UHS/spray pond water inventory is sufficient to enable spray pond operation for slightly more than 26 days without any makeup water supply following the design basis LOCA. This period is nominally the same 26-day period presently discussed in the TS Bases 3/4.7.5, and provides a period of time for alternative sources of water to be made available. The staff questioned how the residual heat removal (RHR) cooldown time was affected by the proposed increased RTP. The licensee stated that the original shutdown cooling system design bounds the proposed power upgrade conditions. The original design analysis for the Palo Verde shutdown cooling system time to cooldown performance utilized a decay heat curve based on a 4000 MWt core thermal power. As this decay heat curve bounds the decay heat curve generated in accordance with BTP 9-2 that was calculated for the 3876 MWt RTP (plus a 2 percent uncertainty), the originally determined cooldown times bound the proposed power uprate cooldown times.

The licensing requirement to cooldown from reactor shutdown to an RCS temperature of 200°F is established by BTP RSB 5-1 and is set at 36 hours. The portion of this period established for the natural circulation cooldown to reach shutdown cooling entry temperature of 350°F is 13.3 hours. The licensee stated that the BTP RSB 5-1 shutdown cooldown analysis was revised as a part of the proposed power upgrade project and it was confirmed that the RCS temperature of 200°F can be achieved in less than 36 hours from reactor shutdown.

The licensee stated that in the original analyses, the predicted time to reach cold shutdown was 19.54 hours. These analyses assumed an essential cooling water flow of 14,000 gpm through the shutdown cooling heat exchanger. The time predicted to reach cold shutdown for the increased thermal power was 20.8 hours. The licensee stated that the reason for the slightly longer time in the proposed increased power analysis was the use of a more conservative EW system flow of 12,600 gpm through the shutdown cooling heat exchanger. The licensee concluded that the 20.8 hours remains below the regulatory requirement of 36 hours.

The staff has reviewed the licensee's submittals and based on the information that was provided, has concluded that the UHS and the EW and SP systems are adequately designed to support the proposed power uprate conditions.

3.6.11 Fuel Pool Heat Loads

The licensee stated that the decay heat inputs into the spent fuel pool heat load have been determined in accordance with BTP 9-2, assuming a RTP of 3876 MWt and accounting for a 2 percent power level uncertainty. The licensee determined that these decay heat values are bounded by the decay heat values used in the present spent fuel pool heat load calculations. The licensee therefore concludes that the proposed 2 percent increase in RTP has no impact on the spent fuel pool and the pool cooling system design.

Also, an issue associated with spent fuel pool cooling adequacy was identified in NRC Information Notice 93-83 and its Supplement 1, "Potential Loss of Spent Fuel Pool Cooling Following a Loss of Coolant Accident (LOCA)," dated

October 7, 1993, and August 24, 1995, respectively, and in a 10 CFR Part 21 notification, dated November 27, 1992. The staff is evaluating this issue, as well as broader issues associated with spent fuel storage safety, as part of the NRC generic issue evaluation process. If the generic review concludes that additional requirements in the area of spent fuel pool safety are warranted, the staff will address those requirements to the licensee under separate cover.

The staff has reviewed the licensee's submittals and, based on the information provided, finds that the spent fuel pool is in accordance with BTP 9-2 and has adequate capacity to support the additional heat loads associated with the proposed uprate conditions.

3.6.12 Fire Protection Program

The licensee stated that the only effect of the proposed 2 percent RTP increase on the PVNGS fire protection program would be the additional decay heat due to the higher power level. The licensee concluded that this effect is negligible.

The staff has reviewed the licensee's submittals and based on the information provided, finds that the proposed 2 percent RTP increase will not adversely impact the fire protection program for the three PVNGS units.

3.6.13 Main Turbine and Balance of Plant

In 1994, the licensee decreased the reactor coolant system hot-leg temperature by 10°F (to 611°F). This change was made to minimize the contribution of high operating temperatures on steam generator tube degradation. Following this change, operating at 100 percent reactor power has been achieved with three of the main turbine control valves full open and the fourth valve approximately 30 percent open.

Reactor operation at 3876 MWt, plus the additional heat added by the reactor coolant pumps and the pressurizer heaters, will deliver approximately 3899 MWt to the turbine. The licensee has determined that the turbine can accommodate the additional heat load with the fourth turbine control valve approximately 90 percent open. The licensee concluded that because the original turbine missile analysis was based on the design condition of 4030 MWt, it continues to be bounding for the proposed increase in RTP.

The staff has reviewed the licensee's submittals and has concluded that because operation of the turbine is bounded by the current licensing analysis, the existing turbine overspeed protection is adequate and operation of the turbine at the proposed uprate conditions is acceptable.

3.6.14 Radiological Waste

The licensee considered the impact of the proposed RTP increase on radiological effluents and determined that there would be no significant increase or change in the type of effluents currently being produced. The licensee's January 5, 1996, submittal indicated that the proposed 2 percent increase in RTP is within the 4100 MWt design stretch power that was evaluated in the Final Environmental Statement - Construction Permit Stage. Given these considerations, the staff finds that radiological waste considerations do not pose a problem for the proposed 2 percent RTP increase.

3.7 Additional Considerations

During a telecon with the licensee on May 9, 1996, the staff questioned the proposed power uprate affects on the following: internal plant flooding, control room ventilation, emergency diesels, and mechanical EQ. In a letter dated May 10, 1996, the licensee stated that these items were taken under consideration for the 2 percent power uprate and that the increased RTP had no affect on these systems. This is consistent with other power uprate submittals that have been reviewed and the staff was satisfied with the licensee's response.

3.8 Summary of Staff Evaluation

The staff has found through reviews of other power uprate submittals, that increases in rated core power on the order of 2 percent are generally within the design capability of the plant. However, licensees must evaluate all areas of plant design and operation that may be affected by the proposed rerate condition to assure that the licensing basis remains valid and that all NRC requirements are satisfied. In particular, the licensee must identify for staff review any conditions that are outside the existing licensing basis, including any new assumptions or methodologies, that have not been previously reviewed and approved by the NRC.

As discussed above, the staff has found that the licensee has adequately addressed existing licensing basis and regulatory requirements as they relate to the proposed 2 percent RTP increase. Therefore, the NRC staff has concluded that reactor operation at the proposed rerate condition is acceptable. However, the staff's acceptance does not constitute approval of methodologies or assumptions unless otherwise stated in this safety evaluation.

4.0 TECHNICAL SPECIFICATION CHANGES

In order to allow the operation of PVNGS at the proposed rerate conditions, the licensee proposed several changes to the facility operating license and associated technical specifications. The proposed changes are as follows:

Revise paragraph 2.C.(1) of the facility operating licenses for each of the three PVNGS Units (License Nos. NPF-41, NPF-51, and NPF-74, for Units 1, 2, and 3, respectively) to increase the authorized 100 percent reactor core power (rated thermal power) from 3800 megawatts thermal (MWt) to 3876 MWt, an increase of 2 percent.

Paragraph 2.C.(1) specifies, as a license condition, the maximum reactor core thermal power level at which APS is authorized to operate each PVNGS unit under the operating license issued by the NRC. The maximum authorized reactor core thermal power level is specified as a license condition in order to limit thermal power to the value used in the safety analyses. The maximum reactor core thermal power specified in the operating license is also known as the rated thermal power. Regulatory Guide 1.49, "Power Levels of Water-Cooled Nuclear Power Plants," Revision 1, issued in 1973, states that licensed power levels for construction permit applications should be limited to a reactor core power level of 3800 MWt or less. In SECY 94-025, the staff informed the Commission of the acceptability of power levels above 3800 MWt for certain evolutionary reactor designs. The design of General Electric's advanced boiling water reactor was found acceptable for a power level of 3926 MWt and Asea Brown Boveri Combustion Engineering's System 80+ was found acceptable for a power level of 3914 MWt (as stated in Section 1.1.2 of NUREG-1462 "Final Safety Evaluation Report Related to the Certification of the System 80+ Design," dated August 1, 1994).

As a result, the NRC has issued final design certification for System 80+ with a licensed thermal power of 3914 MWt. Since the issuance of RG 1.49, Revision 1, in 1973, the staff has reviewed operating experience, including evaluations of performance indicator data, and has determined that power uprate applications can be reviewed on the merits of the individuals' applications. The staff has determined that sufficient experience exists with large plants and licensed units in excess of the administrative limit, the proposed amendment complies with RG 1.49. RG 1.49 also requires a two percent uncertainty in the power level measurement be included in the safety analysis power level. Thus the licensee's safety analysis supporting this amendment used a reactor core thermal power of 3954 MWt, which is 102 percent of 3876 MWt, the proposed new RTP. Therefore, the staff finds this change acceptable.

<u>Revise TS Section 1.26</u>, "Definition of Rated Thermal Power," for each of the three PVNGS Units to increase the rated thermal power from 3800 MWt to 3876 MWt, an increase of 2 percent.

TS 1.26, "Definition of Rated Thermal Power," identifies the licensed limit of the total reactor core heat transfer rate to the reactor coolant. Since this change is consistent with power uprate level evaluated in this SE, the proposed change is acceptable.

<u>Revise TS 3.2.6 (Figure 3.2-1)</u>. The current allowable T_{cold} upper range limit is a curve that begins at 570°F at 0 percent power, drops linearly to 568°F at 30 percent power, and remains at 568°F up to 100 percent power. The revised T_{cold} upper range limit for the area of acceptable operation would begin at 570°F at 0 percent power and drop linearly to 568°F at 30 percent power, as in the current Figure 3.2-1, but then drop linearly to 560°F at 100 percent power. The lower T_{cold} range limit for the area of acceptable operation would be reduced from the current limit of 552°F at all power levels to 550°F at all power levels.

The proposed change will ensure that the actual value of the reactor coolant cold-leg temperature is maintained within the range of values used in the safety analysis. The safety analysis performed to support this proposed amendment utilized the proposed new allowable cold-leg temperature range and thus maintains the basis for the cold-leg temperature limits. The staff finds this acceptable.

Revise TS 4.1.1.4.b, "Minimum Temperature for Criticality - Surveillance Requirements," for each of the three PVNGS units to lower the reactor coolant system cold-leg temperature (T_{cold}) associated with increased surveillance monitoring from 552°F to 550°F.

The proposed change will specify increased monitoring of RCS cold-leg temperature (T_{cold}) when the RCS T_{cold} is below the value used in the safety analyses. This increased monitoring is performed any time cold-leg temperature is below the analyzed range so that the appropriate actions can be taken if the temperature drops below the minimum temperature for criticality. The analysis that supports this proposed amendment analyzes T_{cold} down to 548°F, and, after adding 2°F to compensate for uncertainties, establishes that the increased surveillance frequency be applicable below 550°F. The staff finds this acceptable.

Revise TS 3.1.3.4.a, "CEA Drop Time - Limiting Condition for Operation (LCO)," for each of the three PVNGS units to lower the minimum reactor coolant system cold-leg temperature (T_{cold}) for CEA drop time requirements from 552°F to 550°F. The associated Bases would also be revised to reflect this change.

The proposed change will ensure that CEA drop time testing is performed under normal operating conditions and would be representative of CEA drop times were a trip necessary. The proposed 2°F reduction in the T_{cold} lower limit would have a negligible impact upon CEA drop time, as demonstrated during the 10°F hot-leg temperature reduction program and documented in Unit 2 TS Amendment 65, approved August 12, 1994. The staff finds this acceptable.

Revise TS 3.4.2.1 and TS 3.4.2.2 to lower the pressurizer safety code valve setpoints for PVNGS Units 1 and 3 from 2500 psia to 2475 psia. These setpoints in PVNGS Unit 2 TS 3.4.2.1 and 3.4.2.2 were revised to the 2475 psia value by Amendment 78, approved March 1, 1995.

The proposed change is required to ensure that the safety valves operate to prevent the RCS from being pressurized above 2750 psia (110 percent of design pressure) for anticipated operational occurrences and 3000 psia (120 percent of design pressure) for limiting faults. The pressurizer code safety valves are designed to automatically open to provide overpressure protection for pressure-peaking events. The staff finds this acceptable.

Revise the Bases for TS 3/4.4.8, "Reactor Coolant System-Pressure/Temperature Limits," for PVNGS Units 1 and 3 to reflect the proposed pressurizer safety valve setpoint of 2475 psia described above. This change was made in the Unit 2 TS by Amendment 78, dated March 1, 1995, and is acceptable.

The licensee's proposed schedule for implementation of this proposed amendment is startup of Unit 2 from refueling outage six in May 1996. Unit 1 would implement the proposed amendment following restart from the sixth Unit 1 refueling outage in the fall of 1996.

Unit 3 would implement the amendment on line at the same time as Unit 2, except for the pressurizer safety valve setpoint change, which would be implemented at the next refueling outage. The licensee has performed additional safety analyses for Unit 3 (documented in the safety evaluation section) which demonstrates that the negative moderator temperature coefficient (MTC) present in Unit 3 is sufficient to compensate for not having the reduced safety valve setpoint. The results of the licensee's analyses demonstrate the safety of operation of Unit 3 with a negative moderator temperature coefficient at the increased rated thermal power (RTP). The licensee's analyses bound operation to the end of cycle since the MTC will become more negative as the cycle progresses. The licensee has verified by test that the negative MTC in Unit 3 exceeds the value used in the safety analysis. The staff finds this acceptable.

The staff's review of the proposed changes to the operating license and technical specifications for PVNGS Units 1, 2, and 3 determined that the changes are consistent with the licensee's UFSAR, the design analyses discussed previously, NRC rules and regulations, and would not affect the health and safety of the public. The staff has reviewed the proposed changes and finds them acceptable for operation at the uprate conditions.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Arizona State official was notified of the proposed issuance of the amendments. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32 and 51.35, an environmental assessment and finding of no significant impact was published in the Federal Register on March 19, 1996 (61 FR 11231).

Accordingly, based upon the environmental assessment, the Commission has determined that issuance of this amendment will not have a significant effect on the quality of the human environment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Attachment: Tables

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Date: May 23, 1996

TABLE 1

INPUT PARAMETERS FOR PALO VERDE UNITS 1, 2, AND 3 EVALUATION OF A LARGE BREAK LOSS-OF-COOLANT ACCIDENT

Power level, Mwt	3954
Fraction of core inventory available for leakage, %	
Iodines	25
Noble Gases	100
Initial iodine composition in containment, %	
Elemental	91
Organic	4
Particulate	5
Primary Containment volumes, ft^3	
Main sprayed	2.27×10^6
Auxiliary sprayed	0.20×10^6
Unsprayed	0.15×10^6
Primary containment leak rate, %/day	
0-24 hours after accident	0.10
After 24 hours	0.05
Containment spray iodine removal efficiencies, hr^{-1}	
Elemental (main sprayed region)	20
(auxiliary sprayed region)	10.3
Organic	0
Particulate (main sprayed region)	0.34
(auxiliary sprayed region)	0.11
Decontamination factor	
Elemental iodine	6.51
Particulate iodine	50
ECCS leak rate, cc/hr	1500*
Containment sump volume, ft^3	56,532

* based on licensee's TMI Action Plan III.D.1.1 leakage reduction program

TABLE 1

INPUT PARAMETERS FOR PALO VERDE UNITS 1, 2, AND 3 EVALUATION OF A LARGE BREAK LOSS-OF-COOLANT ACCIDENT
(continued)

Atmospheric dispersion factors		sec/m^3
Exclusion area boundary	(0-2 hrs)	3.10×10^{-4}
Low population zone	(0-8 hrs)	5.10×10^{-5}
	(8-24 hrs)	3.80×10^{-5}
	(1-4 days)	2.00×10^{-5}
	(4-30 days)	8.30×10^{-6}
Control room	(0-8 hrs)	2.19×10^{-3}
	(8-24 hrs)	1.29×10^{-3}
	(1-4 days)	5.04×10^{-4}
	(4-30 days)	1.45×10^{-4}
Control room parameters		
Volume (ft^3)		161,000
Makeup flow (cfm)		1,000
Recirculation flow (cfm)		25,740
Makeup and recirculation filter efficiency (%)		
elemental, organic iodines		95
particulate iodine		99
Unfiltered inleakage (cfm)		10
Occupancy factor	(0-24 hrs)	1.0
	(1-4 days)	0.6
	(4-30 days)	0.4

TABLE 2

CALCULATED THYROID DOSES FOR PALO VERDE UNIT 1, 2, AND 3
LOSS-OF-COOLANT ACCIDENT

LOCATION	DOSE	(rem)	
	Containment Leakage	ESF Leakage	Total
EAB	127.4	0.6	128.0*
LPZ	145.2	0.2	145.5*
Control Room**	13.6	0.1	13.7**

* NUREG-0800 Acceptance Criterion = 300 rem thyroid
** NUREG-0800 Acceptance Criterion = 30 rem thyroid

CALCULATED WHOLE BODY DOSES FOR PALO VERDE UNIT 1, 2, AND 3
LOSS-OF-COOLANT ACCIDENT

LOCATION	DOSE	(rem)	
	Containment Leakage	ESF Leakage	Total
EAB	2.0	< 0.1	2.0*
LPZ	0.9	< 0.1	0.9*
Control Room**	0.9	< 0.1	0.9**

* NUREG-0800 Acceptance Criterion = 25 rem whole body
** NUREG-0800 Acceptance Criterion = 5 rem whole body

TABLE 3

INPUT PARAMETERS FOR PALO VERDE UNITS 1, 2, AND 3 EVALUATION OF A STEAM GENERATOR TUBE RUPTURE ACCIDENT

Power level, Mwt	3954
Primary coolant concentration of dose equivalent ^{131}I	

Pre-existing Spike Value ($\mu Ci/g$)

^{131}I	=	43.9
^{132}I	=	8.8
^{133}I	=	47.7
^{134}I	=	7.2
^{135}I	=	32.3

Volume of primary coolant and secondary coolant	
Primary coolant mass (lbs)	575,200
Secondary coolant mass (lbs)	334,000
Secondary coolant feedwater temperature (°F)	450
TS limits for DE ^{131}I in the primary and secondary coolant.	
Primary coolant DE ^{131}I concentration ($\mu Ci/g$)	1.0
Secondary coolant DE ^{131}I concentration ($\mu Ci/g$)	0.1
TS value for the primary to secondary leak rate.	
Primary to secondary leak rate, maximum any SG (gpm)	720
Primary to secondary leak rate, total all SGs (gpm)	1
Iodine partition factor between SG water and steam	100
Primary to secondary leak released immediately (%)	5
Primary to secondary leak scrubbed into secondary liquid (%)	95
Primary to secondary leakage through rupture (lbs)	
(0 - 2 hr)	285,200
(2 - 8 hr)	516,700

TABLE 3

INPUT PARAMETERS FOR PALO VERDE UNITS 1, 2, AND 3 EVALUATION OF A STEAM GENERATOR TUBE RUPTURE ACCIDENT
(continued)

Letdown flow rate (gpm)		72
Release rate for 1.0 μCi/g of dose equivalent ^{131}I (Ci/hr)		
^{131}I = 12.7		
^{132}I = 13.9		
^{133}I = 20.2		
^{134}I = 26.7		
^{135}I = 23.6		
Atmospheric dispersion factors (s/m^3)		
Exclusion Area Boundary	(0-2 hrs)	3.10×10^{-4}
Low Population Zone	(0-8 hrs)	5.10×10^{-5}
Control Room		1.95×10^{-3}
Control room parameters		
Volume (ft^3)		161,000
Makeup flow (cfm)		1,000
Recirculation Flow (cfm)		25,740
Makeup and recirculation filter efficiency (%)		
elemental, organic iodines		95
particulate iodine		99
Unfiltered inleakage (cfm)		10
Occupancy factor	(0-8 hrs)	1

TABLE 4

CALCULATED THYROID DOSES FOR PALO VERDE UNIT 1, 2, AND 3 STEAM GENERATOR TUBE RUPTURE ACCIDENT

	DOSE (rem)	
LOCATION	Pre-accident Spike	Accident-initiated Spike
EAB*	195.1	48.9
LPZ*	37.0	32.3
Control Room**	3.9	3.3

* Current Licensing Basis = 300 rem thyroid
** NUREG-0800 Acceptance Criterion = 30 rem thyroid

REFERENCES

1. Memorandum from D.R. Muller, Division of Systems Integration/NRR to T.M. Novak, Division of Licensing/NRR, dated December 24, 1984.

2. Memorandum from L.G. Hulman, Division of Systems Integration/NRR to B.W. Sheron, Division of Systems Integration/NRR, dated February 24, 1984.